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October 20, 2014

Via Email
Original via Mail

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Inc. (FEI)
2014 Price Risk Management Review Report

The FEI 2014 Price Risk Management Review Report (Review Report) is hereby attached for review by the British Columbia Utilities Commission (the Commission). The Review Report provides FEI's assessment of price risk management alternatives for meeting the objectives of mitigating market price volatility to support rate stability and capturing opportunities to provide customers with more affordable and competitive rates.

The Review Report includes recommendations by FEI for price risk management strategies that help meet the primary objectives. However, FEI is not making any specific requests for approval within this Review Report. FEI proposes that this Review Report act as a framework for discussion with stakeholders, from which specific requests for approval can be developed. FEI hopes that a consultative approach with stakeholders will lead to a common understanding and agreement of the objectives and strategies and help formulate plans which are responsive to changing market conditions and which meet the objectives in the interests of customers.

FEI proposes a utility workshop approach for the purpose of discussing issues and concerns with the goal of developing mutually acceptable price risk management strategies and plans. FEI recommends a series of half day meetings led by FEI representatives providing relevant background material and information and facilitating the discussions. FEI believes this process will enable full discussion of the issues and address any potential concerns of stakeholders and hopefully lead to some common ground in terms of price risk management objectives and strategies.

If you require further information or have any questions regarding this submission, please contact Mike Hopkins at (604) 592-7842.

Yours very truly,

FORTISBC ENERGY INC.

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachments

FortisBC Energy Inc.

2014 Price Risk Management Review

October 20, 2014

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1. EXECUTIVE SUMMARY

Price risk management plays an important role in mitigating gas market price volatility to help provide stability in rates for customers. This FortisBC Energy Inc. (FEI) 2014 Price Risk Management Review Report (Review Report) emphasizes the need for more price risk management beyond FEI's current strategies. It includes recommendations for more comprehensive price risk management by FEI in light of the recent and coming changes in the natural gas marketplace, customer preferences in terms of rate and bill stability, assessments by independent risk management consultants and what other utilities do. The recommendations include strategies for mitigating market price risk and also positioning FEI to capture any favourable future market price movements to help preserve lower commodity rates for customers. These recommendations include the implementation of a medium term hedging program as well as consideration of longer term strategies, such as long term fixed price purchases and Volumetric Production Payments (VPPs).

FEI is not making any specific requests for approval within this Review Report. This Review Report provides a framework for discussing the recommendations with Commission staff and stakeholders and FEI recommends a utility workshop approach to achieve this. FEI hopes that a consultative approach with stakeholders will lead to a common understanding and agreement of the objectives and strategies and help formulate plans which are responsive to changing market conditions and which meet the objectives in the interests of customers.

This Review Report provides an overview of FEI's alternatives for managing market price risk for core sales customers over the short, medium and longer terms. It includes background information such as a review of FEI's price risk management objectives, the natural gas market price environment, the British Columbia Utilities Commission (Commission) Panel's review of FEI's price risk management in 2011 and its directives, an overview of how FEI sets rates for customers and what other utilities do in terms of price risk management to provide some context. It also includes a discussion of FEI's relevant customer research and the exploration of alternative optional commodity rate offerings. FEI's current price risk management strategies as well as possible alternatives are also assessed.

Recent and coming changes in the natural gas marketplace are a key driver for more comprehensive price risk management. The natural gas marketplace has undergone significant changes during the past few years. The abundance of shale gas and weakened demand following the recession which started in 2008 led to a steady decline in natural gas prices from 2008 to 2012. With one of the warmest winters on record in 2011/12, spot gas prices fell in mid-2012 to their lowest levels in over a decade. However, since that time, changes have occurred in terms of both supply and demand in the gas marketplace and prices have since increased from the lows seen in 2012. In particular, during winter 2013/14, despite near-record levels of natural gas production, demand soared and market prices responded. While North American spot prices increased to their highest level in over five years, regional prices spiked to levels not seen since 2000. This led to significant rate volatility for FEI's customers. Spot market prices have subsequently decreased as mild summer 2014 weather and natural gas storage levels have largely recovered from their low levels at the end of winter 2013/14. Future market prices remain uncertain as a cold 2014/15 winter may again increase prices and volatility, a warmer-than-expected winter may lead to lower prices and provide opportunities to capture favourable market prices for customers.

Looking further out in time, within the next few years, natural gas demand is expected to increase in response to the relatively low North American gas prices and environmental requirements. For example, the retirement of many coal plants, resurgence in industrial activity and the potential for LNG exports will boost natural gas demand. Market forecasts indicate that natural gas demand will catch up to supply and market prices will respond.

The customer research conducted recently and discussed within this Review Report is consistent with previous research and indicates that gas consumers prefer some level of rate stability. The 2005 survey information shows that customers have tolerances in terms of annual rate or bill changes. FEI believes that further research in this regard can provide more insight into these tolerances and help define hedging parameters. Those customers wanting absolute rate certainty can select the fixed rate offerings provided by natural gas marketers under the Customer Choice Program. However, for the remaining majority of customers, FEI believes that its recommended strategies can meet the price risk management objectives. In terms of providing alternative commodity rate offerings, FEI believes that price risk management strategies for the FEI portfolio of customers is more effective and efficient than targeting hedging strategies towards customer-specific commodity options.

Based on these considerations, the Panel's directives and the independent assessments by risk management consultants, FEI believes it is time for more comprehensive price risk management. Not only will this provide the short and medium term price protection customers prefer, but it will also provide the opportunity to help preserve lower commodity rates for customers and secure cost effective supply over the longer term. With the amalgamation of the gas utilities effective January 1, 2015, the proposed price risk management strategies will provide benefits to all of the amalgamated FEI gas entity customers.

2. INTRODUCTION

The primary objectives of FEI's price risk management are to mitigate market price volatility to support rate stability and capture opportunities to provide customers with more affordable and competitive rates. This Review Report is intended to provide an overview of FEI's alternatives for managing market price risk for core sales customers (i.e. rate classes 1, 2 and 3). It includes a review of the natural gas market price environment and an overview of how FEI sets rates for customers to provide some context and what other utilities do in terms of price risk management. It also includes a discussion of FEI's relevant customer research and the exploration of alternative optional commodity rate offerings.

The Review Report includes recommendations by FEI for price risk management strategies that help meet the primary objectives. However, FEI is not making any specific requests for approval from the Commission within this Review Report. FEI proposes that this Review Report act as a framework for discussion with stakeholders, from which specific requests for approval can be developed. FEI hopes that a consultative approach with stakeholders will lead to a common understanding and agreement of the objectives and strategies and help formulate plans which are responsive to changing market conditions and which meet the objectives in the interests of customers. FEI proposes a workshop approach for the purpose of discussing issues and concerns with the goal of developing mutually acceptable price risk management plans.

The strategies within this Review Report are intended to provide a framework for price risk management in different market price environments. In other words, the recommended strategies are responsive to changing market conditions and take into consideration short, medium and long term horizons in meeting the price risk management objectives. Natural gas market conditions can change quickly from one year to the next and so a strategy that works well in one price environment but not in another may not meet the objectives. FEI believes that a portfolio approach, including several different price risk management strategies, can successfully meet the objectives.

Currently, FEI's price risk management portfolio includes several components. Physical resources, such as the use of natural gas storage and market price hub and supply diversity, help mitigate short term market price volatility and ensure security and diversity of supply. FEI's quarterly rate setting mechanism and deferral account balances help to provide some smoothing effect to rates and ensure timely recovery or refund of costs from or to customers.

On an optional basis, the natural gas marketers' fixed rate offerings provided under the Customer Choice program enable customers who want more commodity rate certainty to lock in their rates for terms up to five years. And those customers preferring more stability in their monthly gas bills can sign up for the Equal Payment Plan (EPP).

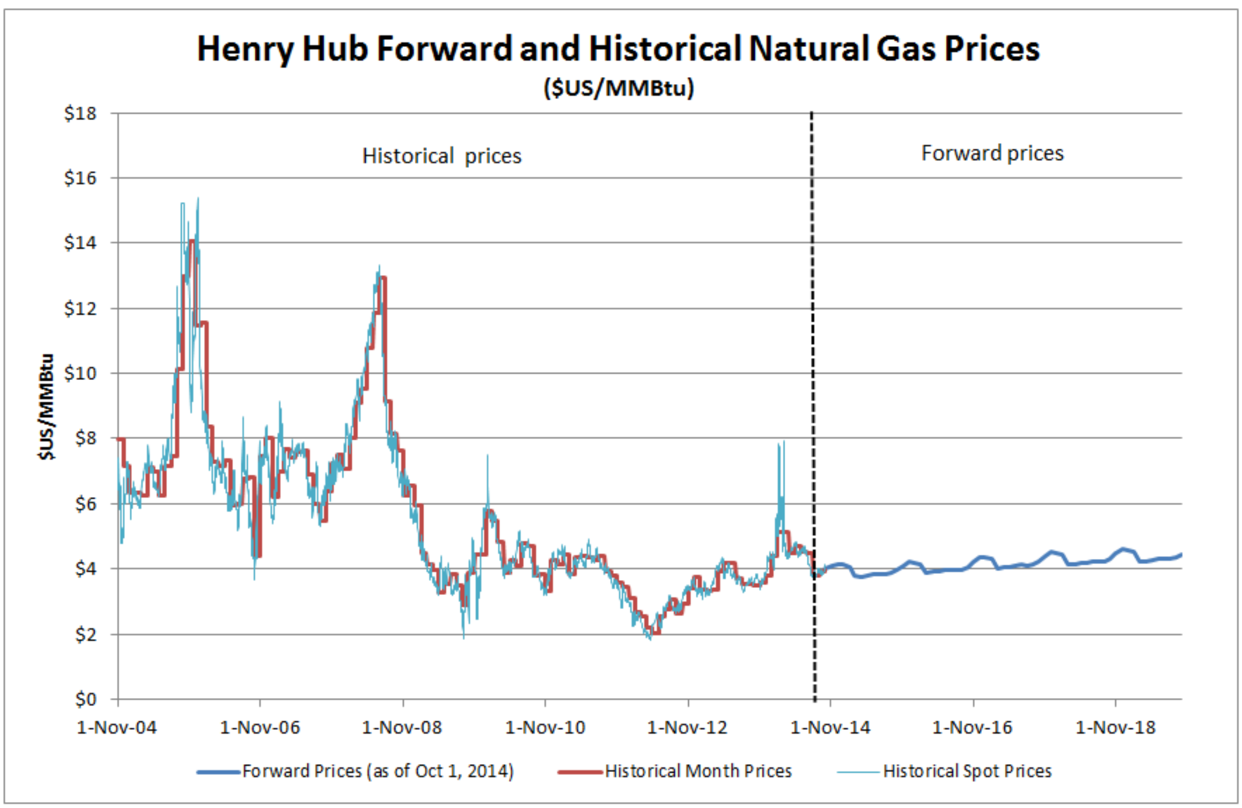
However, while these components do provide some shorter term rate or bill volatility reduction, they do not provide effective price risk management for the medium and longer term given the volatility in the natural gas market and customers' preferences for some level of stability.

Despite the abundance of North American gas supply in recent years due to the surge in unconventional gas production, market prices experienced increased volatility over the past year. During the winter of 2013/14, one of the coldest in decades for most parts of Canada and the US, natural gas storage levels declined to levels not seen in over ten years and prices increased significantly from levels seen in recent years. During winter 2013/14, regional spot market prices, such as Station 2, AECO/NIT and Sumas spiked to their highest levels since 2000. Extended periods of cold weather and lack of pipeline infrastructure to move gas supply to demand were the main factors contributing to the market price volatility. While gas supply continues to grow, it will take time for pipeline capacity to catch up to the demand requirements, meaning that there is still the potential for further market price volatility in the coming years.

Spot market prices have subsequently decreased as natural gas storage levels have somewhat recovered from their low levels at the end of winter 2013/14. While a cold 2014/15 winter may again increase prices and volatility, a warmer-than-expected winter may lead to lower prices and provide opportunities to capture favourable market prices for customers.

At this time, forward market prices continue to remain favourable relative to historical average price levels. This is illustrated in the following figure, which shows historical Henry Hub[1] spot gas prices as well as forward prices as of Oct 1, 2014.

Figure 2-1: Historical and Forward Henry Hub Gas Prices



[1] Henry Hub is the benchmark trading gas supply hub for North America and is located in Louisiana.

Market price forecasts indicate there is greater upside than downside potential for future natural gas prices. The relatively low gas prices of the last few years have resulted in a slowdown in natural gas production growth and also spurred increased interest in the use of natural gas. Natural gas and oil producers have reduced dry gas drilling in order to focus on liquids-rich and oil drilling. In addition, demand has increased for industrial use, such as in the petrochemical and fertilizer sectors, as companies take advantage of the lower feedstock prices. Furthermore, within the next few years, coal plant retirements and LNG exports from North America could add significant amounts of gas demand. Natural gas used for transportation will also add to this demand. Overall, these changes are expected to tighten the market supply and demand balance going forward so that market prices and price volatility increase from current levels.

Recent customer research indicates that many FEI customers continue to be concerned about rate volatility and rising natural gas prices in the future. The 2012 research results show that while many customers prefer an FEI market-based commodity rate, adjusted on a quarterly basis, there is also interest in other alternative offerings. In contemplating providing other potential commodity rate offerings, however, FEI must consider the costs of providing an optional alternative as well as the challenge relating to the general lack of understanding by customers of their natural gas bill and its components, as reflected in the research. Customers have indicated that they want to be protected from rate increases but not locked into a fixed rate product. This indicates that many customers are interested in some, but not absolute, rate stability. This research is consistent with FEI's previously conducted research that helped define the limits of customers' tolerable annual bill increases. This, along with other research, provides evidence that many customers believe it is reasonable for their utility to protect them from adverse market price movements.[2, 3] Therefore, FEI believes that it is more efficient and effective to target its price risk management strategies on its entire portfolio of commodity customers rather than tailor specific strategies for different alternative commodity rate offerings.

More comprehensive price risk management could help to better manage short term market price volatility and position FEI to take advantage of any forward market price opportunities to meet customers' preferences and the objectives. FEI plans to continue its current price risk management activities, such as the use of natural gas storage and quarterly rate setting mechanism and deferral accounts, but recommends expanding certain aspects of its risk mitigation strategy. These include implementing a medium-term hedging program and consideration of longer term alternatives. FEI believes that these will provide FEI with a more complete portfolio of tools to meet the price risk management objectives. It is important to note that the tools within this portfolio work in different ways to mitigate price risk and no single component is entirely effective on its own.

FEI's principal recommendation includes implementing a medium-term hedging component for a portion of the gas supply portfolio to help meet customers' desires for rate stability and

[2] Designing Natural Gas Utility Hedge Programs With Call Options, John Cita, Soojong Kwak, Donald Lien, 2007, page 3.

[3] Terasen Gas Residential Customer Natural Gas Price Volatility Preferences Qualitative Research Study, Western Opinion Research Inc., March 14, 2005, page 12 (provided in Appendix F).

participation in any potential downward market price movements. Further customer research can help define the hedging parameters so that any hedging will be implemented in accordance with customers' rate and bill change tolerances. The program can also be designed such that potential hedging costs are limited to predefined levels.

It is also recommended that FEI implement longer term tools, such as long term fixed price contracts, and consider further review of VPPs for even longer term stability. These tools provide the opportunity to manage longer term periods of price volatility, generally increasing market prices over time as well as provide security of supply.

FEI believes that there should be more consideration of amortizing projected gas costs over a longer period of time to help mitigate rate volatility and manage deferral account balances to appropriate levels. For example, while FEI typically amortizes projected gas costs and accumulated deferral account balances over the next twelve months when setting commodity rates, the rate setting guidelines provide some discretion in allowing for consideration of spreading costs over the next twenty four months. This would be appropriate in the case when there is a significant difference in the forward gas costs between the next twelve months and the subsequent twelve months. In this situation, there is a greater probability of having a rate increase followed by a rate decrease (or vice versa) and deferral account balances exceeding acceptable tolerances.

To help with the development of this Review Report, FEI engaged Aether Advisors LLC (Aether) to provide an independent assessment of FEI's price risk management and recommendations in light of the market environment, tools and instruments available to FEI and customer preferences. This report also takes into account the findings of RiskCentrix, LLC (RiskCentrix) which assessed FEI's price risk management program in 2010 to help with the development of FEI's Price Risk Management Plan Review Report submitted to the Commission on January 27, 2011.

The structure of this Review Report is as follows:

- **Section 1: Executive Summary** – high level summary of the review and recommendations.
- **Section 2: Introduction** – overview of FEI's current and recommended price risk management, review process and the impacts of the gas entity amalgamation.
- **Section 3: Price Risk Management Objectives** - summary of the FEI price risk management objectives.
- **Section 4: Background** – information regarding the Commission review of FEI's price risk management objectives and strategies and 2011 decision, the natural gas market overview and FEI's rate structure and rate setting mechanisms.
- **Section 5: Price Risk Management Alternatives** – summary and assessment of the alternatives available to FEI to manage price risk.

- **Section 6: Other Jurisdictions** – discussion of price risk management in other jurisdictions for comparative purposes.
- **Section 7: Alternative Optional Rate Offerings and Structures** – summary of the Customer Choice program and Equal Payment Plan, customer research and FEI's exploration of alternative optional commodity rate offerings.
- **Section 8: Aether's recommendations** – summary of Aether's review of FEI's price risk management and recommendations for enhancement.
- **Section 9: FEI's Recommendations** – summary of FEI's recommendations for more comprehensive price risk management.
- **Section 10: Review Process and Next Steps** – FEI's recommendations for review of this report and next steps in developing specific requests for Commission approval.
- **Section 11: Conclusion** – summary of the review and recommendations.
- **Appendices** – relevant background information to provide context for the review and support the recommendations.

2.1 *GAS ENTITY AMALGAMATION*

On February 26, 2014 per Order G-21-14, the Commission issued its decision regarding the FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) (collectively, the FEU) Application for Reconsideration and Variance of Order G-26-13 (Amalgamation Reconsideration), in respect of the FEU's Common Rates, Amalgamation and Rate Design Application. The Commission determined that the amalgamation of FEI, FEVI and FEW is in the public interest and approved the proposal to adopt common rates (excluding the service area of Fort Nelson) effective January 1, 2015. Effective upon amalgamation, the Commission approves the use of a combined gas portfolio for the amalgamated entity with shared commodity and midstream rates using the current FEI rate structure and rate setting mechanisms as the model. In the FEU's Common Rates, Amalgamation and Rate Design Application, the FEU discussed the benefits of a single gas portfolio that included greater operational effectiveness, expanded contracting flexibility, and regulatory efficiency[4].

With a single gas portfolio and common commodity and midstream deferral accounts and rate setting mechanisms upon amalgamation, the FEU also recommend a single price risk management strategy. While FEI (including FEW) and FEVI have shared common objectives and used common price risk management tools in the past, they have had different price risk management strategies based upon their unique circumstances. For example, given FEVI's greater challenge in competing with other sources of energy on a cost basis, particularly in the absence of the royalty revenue arrangement with the Province of B.C. which expired at the end of 2011, FEVI's price risk management strategy included financial hedging which targeted specific electricity equivalent price levels and extended further out in time than FEI's program

[4] FEU Common Rates, Amalgamation and Rate Design Application dated April 11, 2012, Section 7.4.3.

(i.e. five years instead of three years). Now, with the approval of amalgamation, a single price risk management strategy is proposed to meet the objectives of the amalgamated entity. This will provide greater regulatory efficiency going forward as the amalgamated entity will have a single strategy and price risk management programs and plans for submission to the Commission.

FEI, as the new amalgamated entity, has moved to a single gas supply portfolio effective the next gas year starting November 1, 2014 as discussed within the 2014/15 Annual Contracting Plan (2014/15 ACP) filed on May 1, 2014 (and accepted by the Commission on July 17, 2014 within Letter L-40-14). Note that FEI's existing financial hedges, implemented according to previously approved Price Risk Management Plans, expired at the end of March 2014; FEVI's hedges expire at the end of October 2014. Therefore, effective November 1, 2014, there will be no hedges in the combined portfolio. For the purposes of this Review Report, the recommended price risk management strategy for FEI is assumed to be applicable to the amalgamated entity.

3. PRICE RISK MANAGEMENT OBJECTIVES

The primary objectives of FEI's price risk management are to mitigate market price volatility to support rate stability and capture opportunities to provide customers with more affordable and more competitive rates than in the past. Protecting customers from market price volatility includes mitigating the impacts of regional price disconnections (i.e. Sumas price spikes). During the 2011 review of FEI's price risk management objectives and strategy, the Commission and stakeholders agreed that moderating the volatility of natural gas prices, including reducing the risk of regional price disconnections, is a reasonable goal for FEI.[5]

However, price risk management is not just about protecting customers from short term market price events or price disconnections. FEI believes it is also about helping to preserve lower commodity and midstream rates as well (relative to past levels). FEI's customer research indicates that many natural gas customers are concerned with rate volatility and rising natural gas prices in the future (see Section 7 and Appendices C to F for more details). As discussed in Section 5, price risk management strategies that position FEI to capture favourable market price opportunities help achieve the objective of providing customers with more affordable and more competitive rates than in the past.

FEI believes that maintaining competitiveness with other sources of energy is an important objective of price risk management. This is because maintaining competitiveness provides customers with cost effective alternatives for their energy use and maintains system throughput which helps to mitigate delivery rate increases. At this time, natural gas' primary competition comes from electricity, as customers do have a choice for energy used for water and space heating. However, other energy alternatives are available to customers, such as ground source heat pumps, which add to the challenge for natural gas. While FEI recognizes that customers, builders and developers make energy choices based on many factors, such as cost, space requirements, ease of installation, etc., cost continues to be an important factor for many decision makers. Keeping midstream and commodity rates as low as possible helps to mitigate the higher capital costs and carbon tax associated with natural gas.

An underlying goal is to meet these objectives in a cost effective manner. It should be recognized that this does not necessarily mean avoiding hedging costs or out-of-market outcomes. The goal of price risk management is not to achieve the lowest possible market price or "beat the market"; rather, it should be thought of like insurance, which comes with a cost. However, the benefits of price risk management should justify the costs.

FEI believes that the current market price environment may provide opportunities to lock in value for customers to meet these objectives. There are several price risk management strategies which would help maintain low commodity rates for customers and also help mitigate potentially higher prices and volatility should they occur in the future. These strategies and alternatives are discussed in Section 5.

5 Commission Order G-120-11, Appendix A, page 22.

4. BACKGROUND

The following sections provide some background information to help set the context for the discussion of price risk management tools, strategies and recommendations. The first section provides a discussion of the Commission review of the FEU's price risk management objectives and strategy which occurred in 2010 and 2011. The second section provides an overview of the natural gas marketplace and developments occurring within it. The last section provides an overview of the FEI rate structure and rate setting mechanisms.

4.1 *COMMISSION REVIEW OF PRICE RISK MANAGEMENT OBJECTIVES AND STRATEGY*

In 2010, a Commission Panel (the Panel) was established to review the FEU price risk management objectives and FEI hedging strategies within the FEI 2011-2014 Price Risk Management Plan (PRMP) dated January 27, 2011 (the Review). The Commission established this Review in light of the significant changes in the natural gas marketplace that began in 2008, in particular the increase in natural gas supply and reduction in market prices due to the abundance of shale gas, and the objective of competitiveness in the context of B.C. energy objectives as set out in the *Clean Energy Act (CEA)*. The Review included a written public hearing process in 2011 which involved Commission staff and interveners including the Commercial Energy Consumers Association of B.C. (CEC) and the British Columbia Public Interest Advocacy Centre (BCOAPO)[6]. The Review focused on the objectives of the hedging program, its performance over its last few years and the FEI proposed enhancements to the hedging strategy.

As part of the Review, given the changes in the market environment, FEI had proposed an enhanced hedging strategy which was more responsive to changing market conditions. It included a shift away from the largely programmatic approach to one that included several components which are more effective in different market price environments. A programmatic approach involves layering in hedges according to a predefined schedule for future periods. It has the benefits of being transparent, easy to administer, and is non-speculative in nature. Its disadvantage is that it is not responsive to changing market conditions. On the other hand, a more responsive, enhanced strategy would include different instruments and implementation plans for different price environments. This approach helps to meet the price risk management objectives and provide balance between mitigating rate volatility and minimizing any potential hedging costs. FEI had proposed the following components as part of the enhanced hedging strategy:

- Value hedging to capture favourable low market prices if they materialized in order to help preserve low commodity rates;

[6] British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre (BCOAPO), previously identified as BCPIAC.

- Programmatic hedging to provide some base for commodity rate stability;
- Defensive hedging using options if market prices moved higher to provide price protection while reducing out-of-market outcomes; and
- Sumas basis hedging to mitigate winter Sumas price disconnections by locking in the differential between Sumas and AECO/NIT forward prices.

This strategy took into account the recommendations by RiskCentrix, an independent and experienced risk management consulting company, as part of the review of its hedging objectives and strategy[7].

4.1.1 Panel Decision

The results of the Review and the Panel decision were provided in Commission Order G-120-11 dated July 22, 2011 (provided in Appendix J). Within this Order, the Panel determined that the need for the objective related to the competitiveness of natural gas with other energy sources had not been established and that promoting the use of natural gas over electricity was not consistent with government policy objectives and the *CEA*[8]. The Panel acknowledged that moderating the volatility of natural gas prices is a reasonable goal and that reducing the risk of regional price disconnections should be part of that goal[9]. However, the Panel did not accept the FEI 2011-2014 PRMP (with the exception of Sumas basis hedging), which included the proposed enhanced hedging strategy. In its decision, the Panel concluded that, based on historical results, in its view, hedging was not the most cost effective approach in mitigating market price volatility. The Panel appeared to focus on historical hedging results rather than the enhanced hedging strategy proposed by FEI. As a result, the FEU were directed to suspended all hedging activity with the exception of the FEI winter Sumas-AECO/NIT basis swaps.

The Panel's view was that short term price volatility can be managed through the use of existing mechanisms such as gas cost deferral accounts, the Equal Payment Plan and the Customer Choice Program. However, in the Panel's view, other than the fixed commodity rate offerings provided by natural gas marketers, these mechanisms may not be effective in managing longer periods of price volatility should they occur in the future. Therefore, the FEU were directed to explore alternatives that would help manage potential longer periods of persisting price volatility[10].

The Panel also emphasized choice for customers in FEI's assessment of alternatives for price risk management. FEI was directed to explore alternative commodity rate offerings for customers and those willing to elect for rate certainty should also be the ones to benefit or incur the cost burden.

[7] RiskCentrix, Findings and Recommendations Regarding Energy Risk Mitigation Program prepared for Terasen Gas, December 27, 2010.
[8] Commission Order G-120-11, Appendix A, page 22.
[9] Commission Order G-120-11, Appendix A, page 22.
[10] Commission Order G-120-11, Appendix A, page 25.

In its decision, the Panel recognized the potential for higher gas prices and volatility in the future, particularly given the potential for increased natural gas demand arising from such things as LNG exports from Canada and the U.S. and economic recovery. The Panel acknowledged that downward market price movements are limited while upward price movements could be greater. Furthermore, the Panel urged the FEU to explore new alternatives to reduce the impacts of market price volatility should the FEU believe that it is warranted. The Panel suggested that the FEU consider the Price Stability Fund (PSF) proposed by CEC as well as a commodity rate offering that employed the proposed enhanced hedging strategy. The Panel emphasized that any considered alternative rate offerings such as these should be provided on an optional basis to customers so that they have a choice when it comes to rate stability and the price they are willing to pay for it[11].

4.1.2 Discussion of Panel Decision

FEI continues to believe that price risk management should include effective use of a portfolio of physical and financial instruments and tools to ensure reliable supply, protect customers from adverse market price movements and help provide customers with more affordable and competitive rates. Different instruments and tools work in different ways to mitigate short term price volatility as well as ensure greater rate certainty over the longer term if market prices rise in the future. For example, while deferral accounts and the quarterly rate setting mechanism do provide some short term rate smoothing effects and should be a part of price risk management, they do not lock in or cap market prices and therefore gas costs and so do not protect customers from underlying market price volatility (see Section 5.2 for further details). Similarly, the Equal Payment Plan (EPP) does provide smoothing in terms of bill payments but, in the end, does not protect customers from underlying market price volatility.

FEI believes that one of the most effective tools to manage market prices is the use of hedging instruments. Hedging should be one of the tools within a portfolio approach and it can be used in several different ways for both the short term and longer term. For example, fixed price swaps can lock in forward market prices at levels near or below current or historical average commodity rates, helping average down future commodity rates in the short term. If necessary, basis swaps can be used to lock in the price differentials between two market price hubs for a winter period to reduce the risk of severe price disconnections due to peak regional demand. Call options could be used to limit the impacts of upward market price movements over a period of several years, protecting customers from rising market prices over time at minimal cost. Long term hedges or fixed price purchases (i.e. up to ten years) could be used to provide long term cost certainty within the gas supply portfolio and also potentially provide greater certainty regarding security of supply. This is discussed further in Sections 5.1 and 5.3.

Consideration should also be given to even longer term forms of price risk management, including investment in reserves and VPP arrangements. FEI believes that this strategy is consistent with the Panel's directives to explore longer term alternatives. Further discussion is provided in Sections 5.1.4 and 5.1.5.

[11] Commission Order G-120-11, Appendix A, page 25.

In terms of commodity rate choice for customers, as part of this review, FEI has also considered providing alternative optional commodity rate offerings for customers (see Section 7). FEI's recently conducted customer research indicates that customers prefer some level of stability but do not want to be locked into paying higher rates when market prices fall. This is also evidenced by the declining enrolments of customers with natural gas marketers. Challenges to FEI providing an optional alternative rate offering to customers include customers' general lack of understanding of their gas bill and natural gas markets. Furthermore, the added billing complexity, administration, education and system requirements and costs would also be challenging in providing commodity rate options. Therefore, FEI believes that it is more efficient and effective to provide price risk management on a portfolio basis for all its commodity customers rather than tailoring specific strategies for different alternative commodity rate offerings.

With regard to cost effectiveness, FEI believes that the recommended enhanced hedging strategy would provide improvements due to two main reasons. Firstly, the enhanced hedging strategy is more responsive to changing market conditions rather than being mostly programmatic and so the likelihood of significant out-of-market outcomes is reduced. Secondly, forward market prices are well below levels of a few years ago and are much closer to production break even costs for many, especially dry, gas plays (as discussed in Appendix A). This also reduces the possibility of significant hedging costs relative to a few years ago. Aether provides the following perspective in its review report regarding FEI's hedging strategy:

> *"Some commissions have ordered utilities to reduce their price risk management programs because of the "cost" of the program was excessive. But in most cases, this determination was made in a vacuum, with minimal consideration for the risk to customers. Reduced hedging has less "cost" in declining markets, but the choice to scale back the hedging is making a bet on the direction of prices. Also, a decision to reduce a program without a quantitative assessment of potential risk exposure to customers, fails to protect customers' interests. Deciding not to hedge when prices are low will not provide much opportunity to customers and instead pose significant risks"*[12].

The Panel stated that it had not "closed the door" on consideration of all future hedging and that it would reconsider hedging again if market conditions changed[13]. FEI believes that market conditions are changing and will continue to change as demand catches up with supply. After several years of relatively low gas prices and no major price spikes from 2010 through 2012, significant gas price volatility returned to the market during winter 2013/14. This clearly highlights the impacts weather or other supply/demand imbalances can have on market prices despite the continued abundance of shale gas. FEI and many market analysts expect this supply and demand balance to tighten in the coming years as demand growth catches up to supply (see Appendix A for further details). This could result in more market price volatility in response to market or weather events in the future.

[12] Price Risk Management Strategies and Tools, Aether Advisors LLC, February 2014, page 12.
[13] Commission Order G-120-11, Appendix A, page 25.

The following section provides more discussion regarding these developments in the natural gas marketplace in terms of supply, demand and pricing.

4.2 *NATURAL GAS MARKET OVERVIEW*

This section provides an overview of the North America natural gas marketplace. More details regarding supply and demand factors and prices are provided in Appendix A.

Significant changes have occurred in the natural gas market during the past few years. In the few years leading up to 2009, the natural gas supply and demand balance was relatively tight and natural gas imports from overseas into North America were being considered to counter the declining supply to meet domestic demand. During this period spot natural gas prices were often near $6 US/MMBtu and market price volatility was high during periods of high demand or supply disruptions (see Figure 4-1 below). Since 2009, strong growth in shale gas production and weakened demand, following the recession which started in 2008, created an over-supplied marketplace. These factors, combined with one of the warmest winters on record in 2011/12, caused natural gas prices to fall to their lowest level in a decade by mid-2012.

However, since that time, changes have led to a tighter supply and demand balance and higher natural gas prices and volatility. After mid-2012, gas prices have increased primarily due to higher gas demand for power generation, the return of some industrial demand and the return to more normal winter weather for 2012/13. Winter 2013/14 was one of the coldest winters in decades. Gas production has remained high but its growth has slowed as gas market prices are close to break-even costs for many dry gas plays and oil drilling is more profitable.

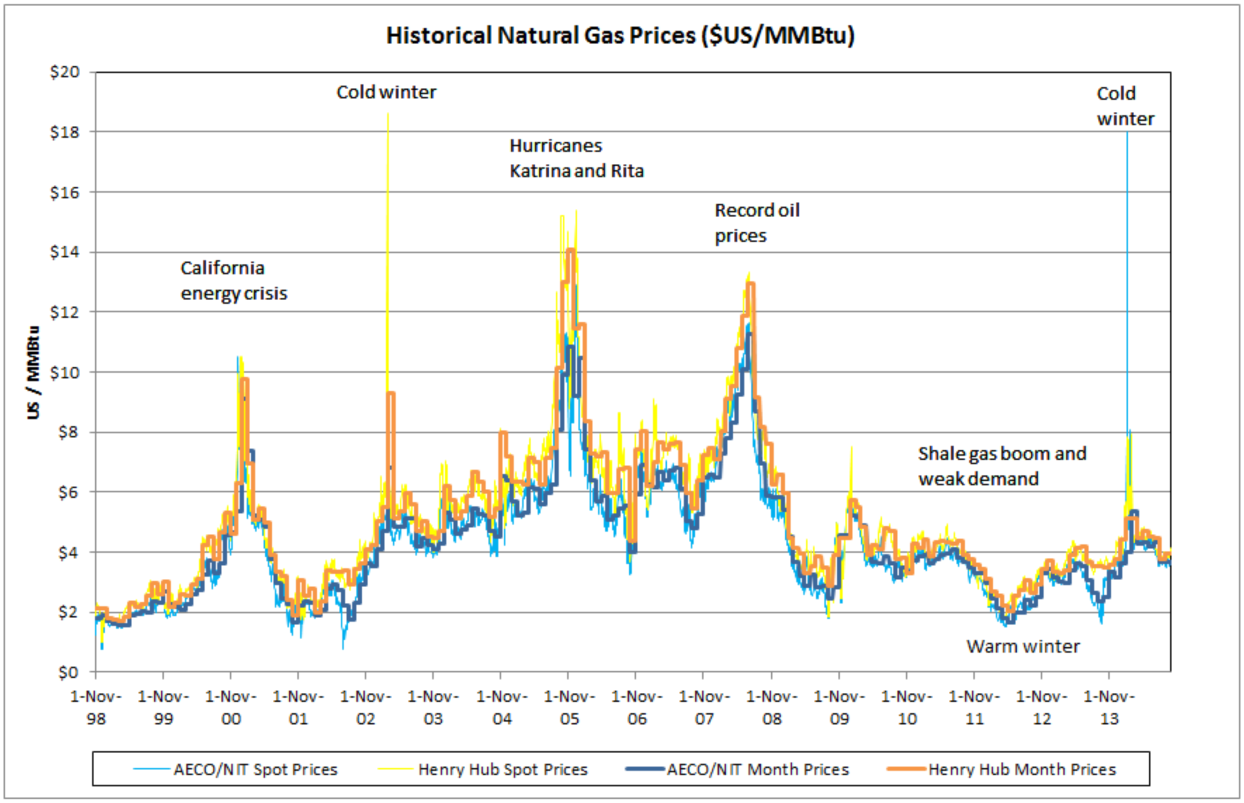
4.2.1 Spot Gas Prices

Spot gas pricing refers to gas prices for next-day delivery of natural gas. Spot prices are highly volatile as they respond to immediate short-term supply and demand factors, especially weather. Spot gas prices fell to their lowest level in a decade in mid-2012 as U.S. gas storage levels were high following the warm winter of 2011/12. In April 2012, Henry Hub spot prices fell to $1.83 US/MMBtu. However, this price dip did not last long as it was well below break-even price levels for many gas producers and so was not sustainable.

During December 2013, with a cold start to winter 2013/14, natural gas spot prices climbed back up to over $4.50 US/MMBtu. Then, the coldest winter in decades hit North America in 2013/14, reducing storage balances to levels not seen in over ten years, causing gas prices to increase. A contributing factor to the higher prices and volatility during winter 2013/14 was also the decrease in available gas supply as production levels in many areas were reduced by well freeze-offs. In early February 2014, Henry Hub spot gas prices reached $7.84 US/MMBtu and AECO/NIT spot prices spiked as high as $18.94/GJ. While the abundance of shale gas has been significant in recent years, pipeline infrastructure required to move this supply to markets has not kept pace and so it does not take long for weather-related demand to alter the supply/demand balance and lead to increased volatility and higher prices in the short term.

The following figure shows historical natural gas spot prices for the past fifteen years (with Henry Hub being the benchmark for North America and AECO/NIT being the benchmark for the Alberta market).

Figure 4-1: Historical Natural Gas Spot Prices

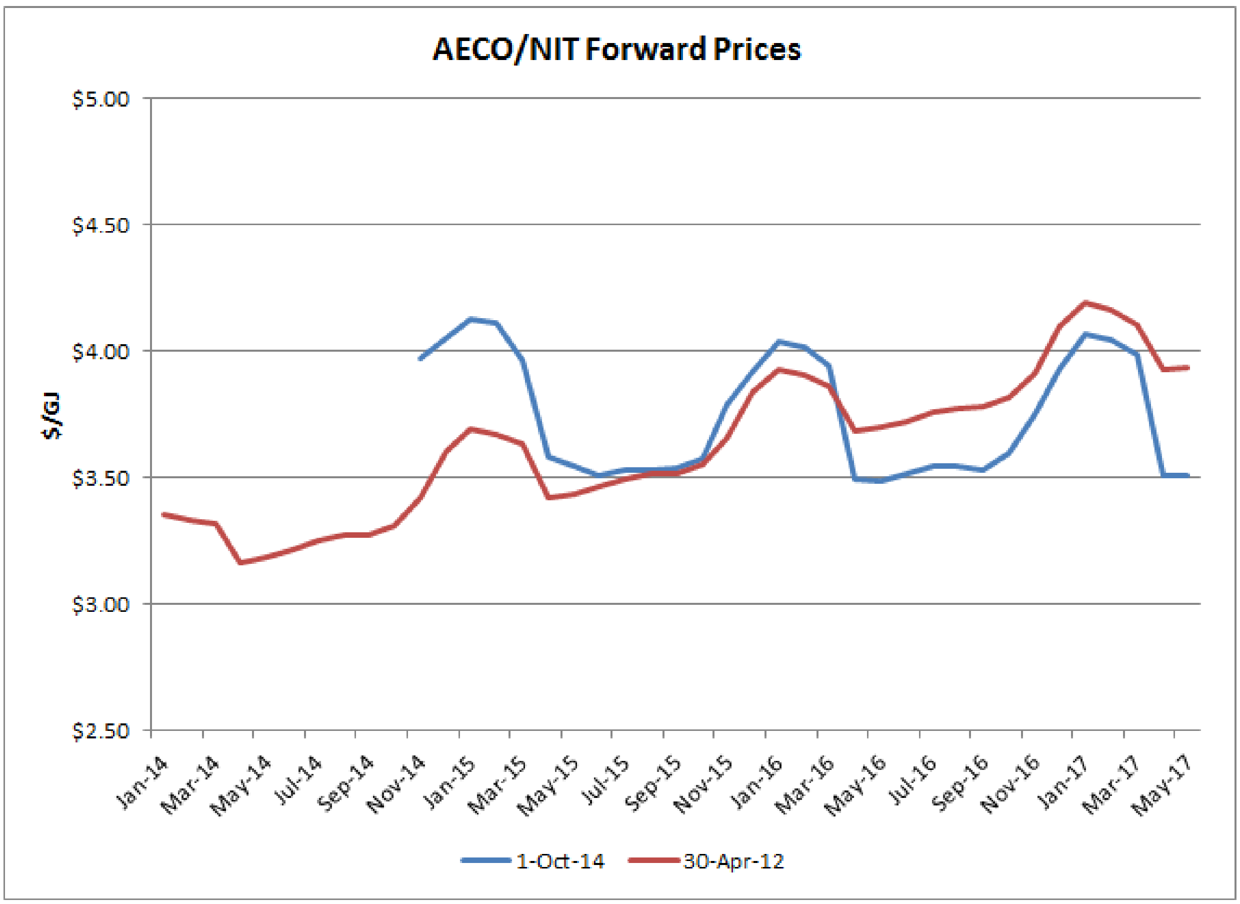


With gas storage balances in North America coming out of winter 2013/14 at their lowest levels in over a decade, there was uncertainty at that time regarding how full storage facilities would be at the start of the next winter 2014/15. However, with a mild summer for 2014 and continued growth in gas production, especially in the Marcellus play, storage levels have recovered to near historical averages prior to the start of winter, although levels are still below those from a year ago. Because of this, recent spot gas prices are favourable compared to historical averages but above year-ago prices. While an early or cold start to winter 2014/15 may increase spot prices and volatility, a late start or a warm winter may result in a decrease in spot prices and volatility. This may provide opportunities for FEI to capture lower forward prices in the interests of meeting the objectives.

4.2.2 Forward Gas Prices

Forward gas pricing refers to currently transacted market gas prices for future periods, typically for the next month and beyond. Spot market prices, on the other hand, are transacted for the following day and react to short-term events, like cold weather spells. The recent depletion of gas storage levels had also put upward pressure on near-term (i.e. for the upcoming winter) forward market prices. This is because there was uncertainty regarding whether or not gas storage levels would be filled to comfortable levels by the next winter. Despite this, forward market prices further out in time, such as in 2015 and 2016, did not increase as much and continue to remain at favourable levels. This is due to the expectation that the significant growth in natural gas supply will be able to match future demand and that, under normal weather conditions, gas storage levels will meet demand requirements. This can be inferred by looking at recent changes in the slope of the forward market gas price curve (using AECO/NIT pricing). While AECO/NIT spot gas prices dropped to their lowest level in a decade in mid-2012 and have since rebounded (like Henry Hub gas prices), forward AECO/NIT natural gas prices for terms further out in time, like 2016, are below where they were in April 2012. The following figure shows these forward price curves.

Figure 4-2: AECO/NIT April 2012 vs. Recent Forward Gas Price Curves



The current forward market prices provide opportunities for FEI to help preserve lower commodity rates for its customers. By using hedging, FEI can lock in current forward market prices for specific periods. Currently, forward market prices are below historical averages and some terms are below or near FEI's current $3.78/GJ commodity rate. Forward prices for terms starting November 2014 through October 2019 range between about $3.50/GJ and $4.25/GJ, with most terms below FEI's historical five-year average commodity rate of about $4.08/GJ[14]. The following table shows the AECO/NIT forward market prices for winter and summer terms out to summer 2019 as of October 1, 2014.

Table 4-1: Forward AECO/NIT Gas Market Prices as of October 1, 2014

Term	Market Price ($/GJ)
Winter 2014/15	$4.05
Summer 2015	$3.54
Winter 2015/16	$3.94
Summer 2016	$3.53
Winter 2016/17	$3.96
Summer 2017	$3.56
Winter 2017/18	$4.06
Summer 2018	$3.69
Winter 2018/19	$4.24
Summer 2019	$3.83
Average	$3.84

The medium term hedging and longer term fixed price purchase strategies, as recommended in this Review Report, would position FEI to capture favourable market price opportunities if they occur in the interests of maintaining lower commodity rates for a period of time for customers. Aether states: "Prices are unlikely to stay low forever. A reduction in market price and market volatility should be seen as an opportunity to hedge at more attractive levels."[15]

4.2.3 Factors leading to higher prices

Despite the strong growth occurring in the Marcellus shale gas basin in the eastern U.S., overall North American natural gas production growth has slowed as natural gas producers curtail dry gas development in response to low gas prices and expiring hedges. Furthermore, higher crude oil and liquids prices have provided the incentive for natural gas producers to shift from dry gas drilling to liquids rich and oil plays (see Section 2 of Appendix A for more details).

On the demand side, low natural gas prices have provided incentives and opportunities for greater use of natural gas. Higher natural gas demand has come from several key areas, including greater industrial demand, greater use of gas for power generation and higher residential and commercial loads due to cold winter weather. Over the longer term, greater gas demand will come from the retirement of aging coal plants, growth in industrial demand, LNG exports from the U.S. and Canada and growth in the use of natural gas vehicles (see Section 3 of Appendix A for more details).

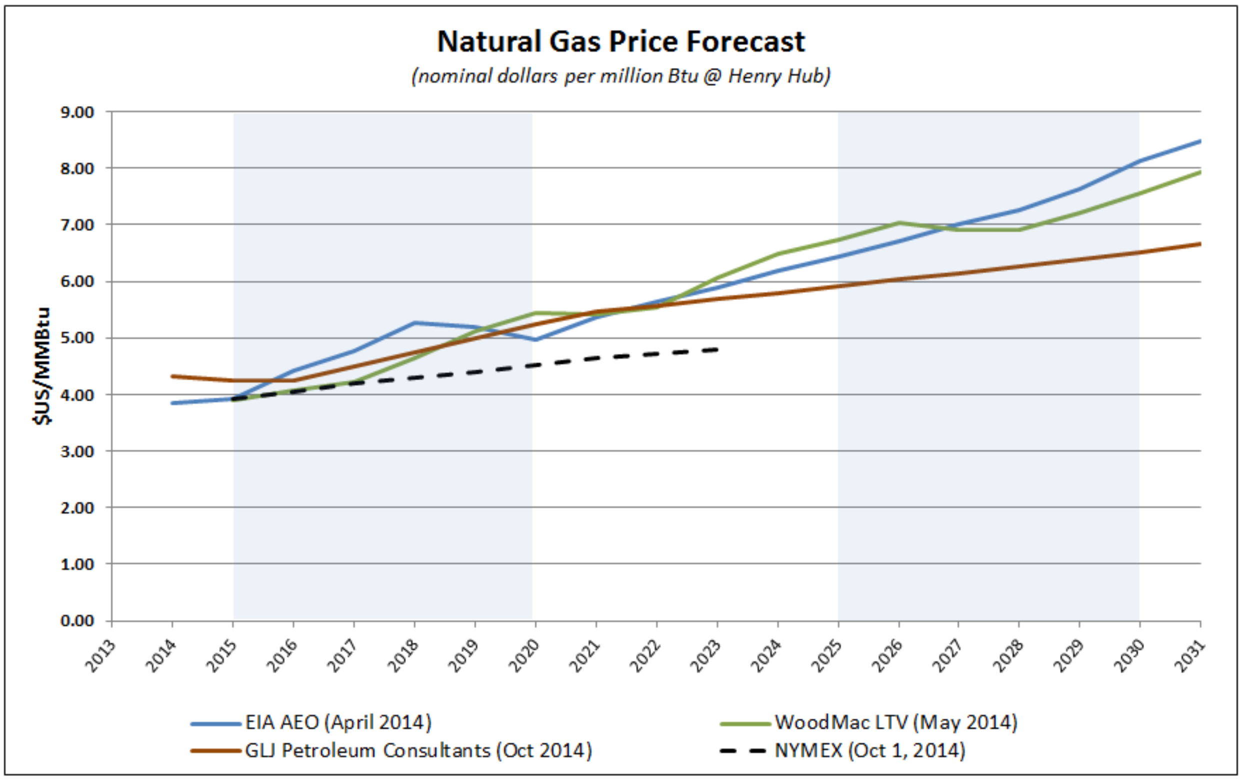
While there is enough gas supply potential to meet this increase in demand given the technological advances in shale gas production, the incremental supply will come at a higher

[14] Based on simple, unweighted average of FEI commodity rates effective October 1, 2009 to October 1, 2014.
[15] Aether Advisors LLC, The Future of Utility Hedging, September 12, 2012.

cost to incent producers to switch back from the more lucrative oil and liquids-rich drilling. For example, ConocoPhillips, one of the largest gas producers in North America, recently stated that they need to see gas prices stay over $5/MMBtu for as long as two years before the company would begin to increase spending on natural gas[16].

Given these factors, it is acknowledged by many market participants that natural gas prices in the future are expected to increase above current price levels as supply and demand becomes more balanced. This is reflected in recent price forecasts, shown in the following figure. The figure also shows a recent forward price curve, represented by 'NYMEX (Oct 1, 2014)'.

Figure 4-3: Natural Gas Price Forecasts (Henry Hub)



A good characterization of natural gas market prices was recently provided by Concentric Energy Advisors (Concentric): "History has repeatedly shown that commodity market conditions are never stagnant, and that markets often correct as supply and demand factors re-balance. Current market conditions could well be the hiatus before the next storm, with forward markets providing opportunities for utilities to lock in low insurance costs for customers."[17] More comprehensive price risk management would enable FEI to better protect customers from market price spikes and capture opportunities to reduce rate volatility and preserve lower commodity rates.

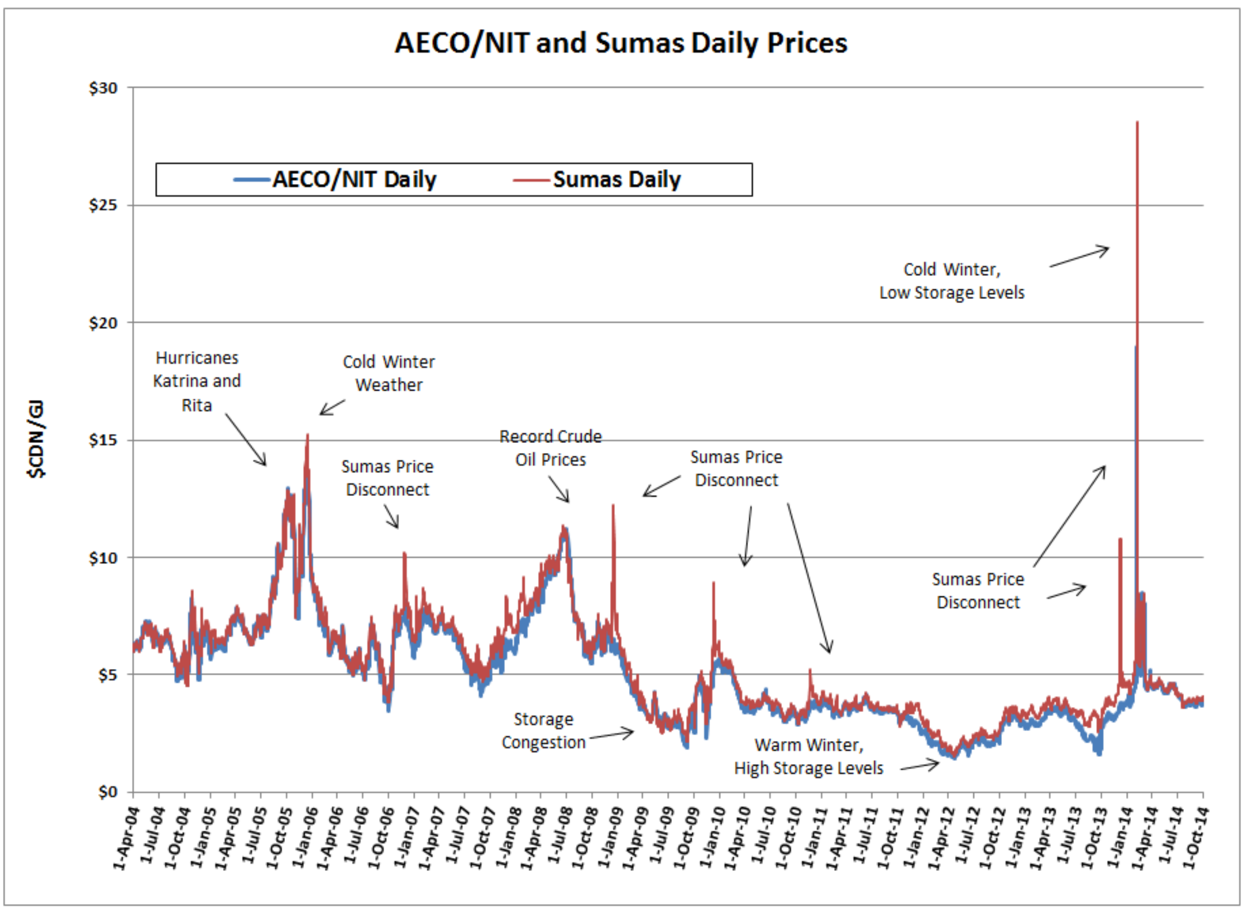
[16] http://business.financialpost.com/2014/02/10/natural-gas-drillers-wary-as-some-see-year-long-supply-squeeze/?__lsa=88d2-7481

[17] Concentric Energy Advisors, New Trends in Utility Hedging Programs, September 2011.

4.2.4 Sumas Price Volatility

While North American gas prices have increased and become more volatile since 2012, regional prices have also become more volatile. Sumas prices at the Huntingdon market hub can disconnect from other regional market prices such as AECO/NIT or Station 2. This occurs during periods of peak winter demand in the Pacific Northwest due to constrained regional infrastructure in terms of pipelines and storage facilities. One recent example of this price disconnection occurred during early December 2013 when cold weather hit the PNW region and Sumas prices spiked to over $10 US/MMBtu while AECO/NIT and Station 2 prices remained below $4 US/MMBtu. Another cold spell and period of high demand during early February 2014 caused Sumas prices to spike again. However, during this event, AECO/NIT and Station 2 prices also rose significantly as the persistent cold winter in Alberta and eastern parts of Canada and the U.S. increased demand and reduced storage balances to levels not seen in many years. The daily prices at AECO/NIT and Station 2 during this cold spell almost reached $20/GJ. The following figure shows the Sumas price disconnections in recent years.

Figure 4-4: AECO/NIT and Sumas Spot Prices



Without any significant changes to regional infrastructure, in terms of pipeline or storage resources, in the near future, and the potential for increased regional demand, this Sumas price risk is not expected to end anytime soon.

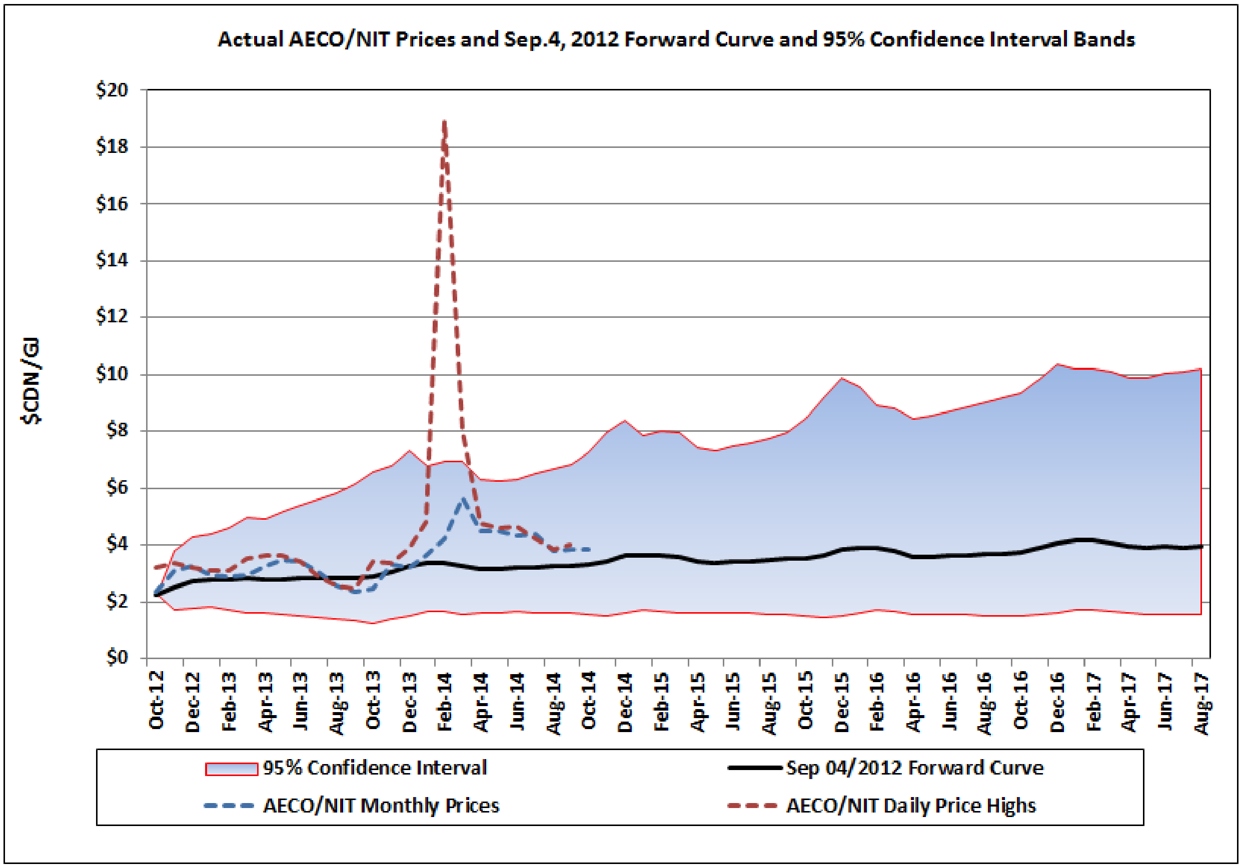
4.3 *DISCUSSIONS FROM THE GENERIC COST OF CAPITAL PROCEEDING*

The subject of natural gas prices and price volatility was discussed during the FEI Generic Cost of Capital (GCOC) Proceeding (Stage 1) during 2013. In this proceeding, FEI provided its view that market price volatility had not diminished since 2009, despite the decline in overall market gas prices. In its decision dated May 10, 2013, the Commission agreed[18]. However, the Commission did note that the September 4, 2012 AECO/NIT forward price curve, provided during the proceeding, projected relatively stable forward prices out to 2017 and concluded that this indicated some level of stability over the next few years[19]. In fact, this has not been the case. FEI would like to clarify that a forward curve does not reflect any potential or actual price volatility in the gas marketplace. Instead it represents transacted prices on a particular date, for example on September 4, 2012, for delivery of gas at a certain point in the future. As such, the forward price curve does not reflect the potential variability in future prices based on changing market supply and demand factors nor where future market prices will ultimately settle. The forward price curve at a particular point in time does not necessarily indicate that prices will remain relatively stable during the projected time period. In fact, the only way to guarantee market price stability based on the forward price curve at a point in time is to lock in market prices at that time. An effective way of doing this is to use natural gas hedging instruments.

As discussed in Section 4.2 of this Review Report, market gas prices have not been stable since September 2012 and have exhibited more volatility during winter 2013/14 than seen in many years. During this time, FEI has flowed through two commodity rate increases, for more than $0.80/GJ or about 25 percent of the commodity rate in each increase. These were the first commodity rate increases FEI has put through since April 2010. The following figure shows the September 4, 2012 forward AECO/NIT prices and 95 percent probability range with the actual AECO/NIT monthly prices and daily spot high prices for each month. Note that the actual daily spot high prices far exceed the 95 percent price probability range predicted back in September 2012 while the actual monthly prices approached the upper end of the probability range.

[18] Generic Cost of Capital Proceeding (Stage 1), Commission Decision May 10, 2013, page 32.
[19] Generic Cost of Capital Proceeding (Stage 1), Commission Decision May 10, 2013, page 32.

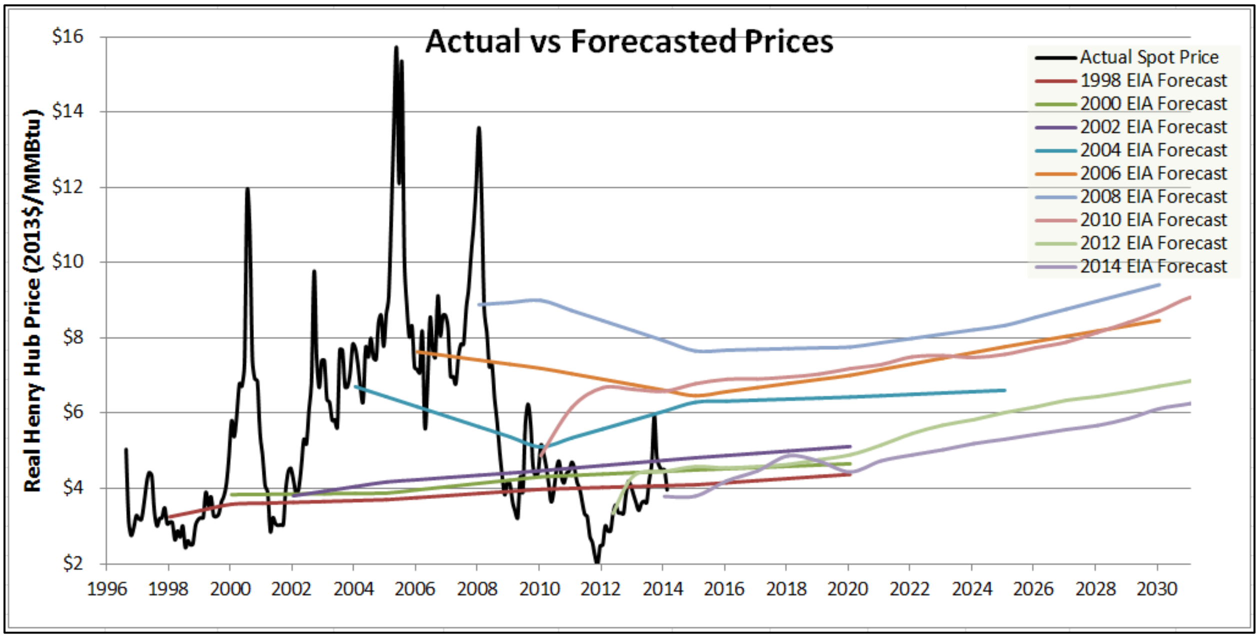
Figure 4-5: AECO/NIT Actual Prices vs. September 4, 2012 Forward Price Curve



On a related note, Northwest Natural Gas Company (NWN) also discusses the difference between forecasted and actual market gas prices in its latest 2014 Integrated Resource Plan (IRP). On Page 1.16, NWN shows historical actual spot market gas prices compared to market price forecasts by the U.S. Energy Information Administration (EIA) at two-year intervals as follows[20].

[20] NWN 2014 Integrated Resource Plan, page 1.16.

Figure 4-6: Actual Prices vs. Forecasts



NWN makes the following observations when comparing actual and forecasted prices[21]:

- Actual prices are more volatile than forecasted prices;
- Forecasted prices are usually too high when prices are high and too low when prices are low - i.e., they are overly influenced by then-existing market conditions; and
- Market gas prices are currently lower than the average price over the last 20 years.

In the GCOC proceeding, the Association of Major Power Consumers (AMPC)/CEC asserted that market gas price volatility is manageable through mechanisms like equal payment plans and deferral accounts.[22] FEI acknowledges that these tools help manage some limited rate and bill volatility. However, equal payment plans and deferral accounts do not directly impact market pricing and so do not effectively manage underlying market price volatility or market price increases. Other price risk management tools, such as hedging, do directly manage market prices and this underlying market price volatility.

4.4 *REVIEW OF FEI RATE STRUCTURE AND RATE SETTING MECHANISMS*

This section provides background information regarding FEI's rates and rate setting mechanisms to show how market developments and gas prices can impact rates for customers as well as the ability of these tools to mitigate market price risk. FEI's commodity and midstream rate structure and rate setting mechanisms will continue as the model used for the amalgamated entity.

[21] NWN 2014 Integrated Resource Plan, page 1.16.
[22] GCOC Proceeding (Stage 1), Commission Decision May 10, 2013, page 32.

4.4.1 FEI Rate Components

FEI's rate structure for core sales customers includes the cost of gas and delivery charges. The cost of gas charges are related to the commodity and midstream components and currently represent about half of the typical Lower Mainland residential customer's bill[23].

The commodity component includes the baseload supply (based on forecast annual load requirements for core sales customers) provided to customers from FEI or gas marketers under the Customer Choice program. The commodity supply is based on predefined receipt point allocation percentages at the Station 2, AECO/NIT and Huntingdon market hubs. Effective November 1, 2013, commodity supply was sourced from Station 2 and AECO/NIT only due to concerns with Huntingdon supply reliability and Sumas price risk[24]. The commodity component costs are captured within the Commodity Cost Reconciliation Account (CCRA). This commodity supply is purchased in the natural gas marketplace from gas producers and marketers based on market index prices. Without any hedges in place within the CCRA, FEI's customers are highly exposed to the market price volatility in the natural gas marketplace.

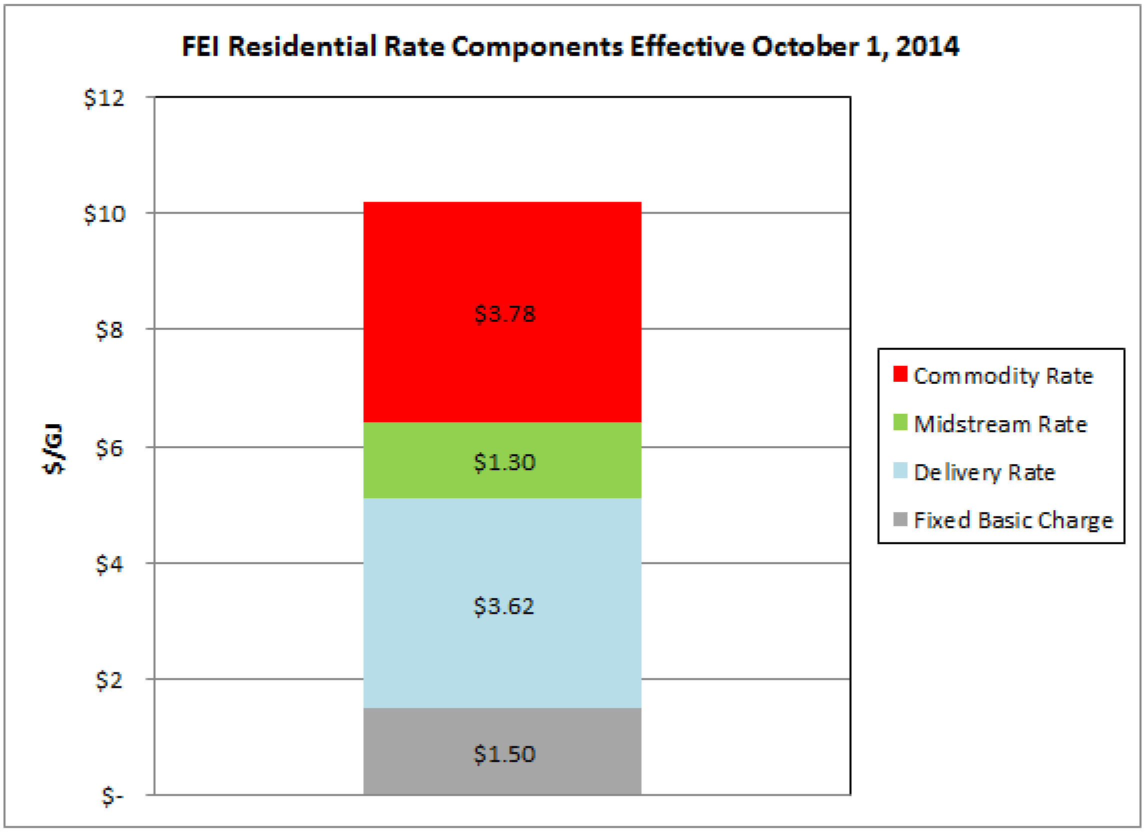
The midstream component includes the supply, transportation, commodity and peaking resources required above the commodity supply to meet customer loads in the winter time. They include costs related to contracting on third party pipelines, storage facilities and seasonal, peaking and spot supply. As the midstream costs include a large amount of pipeline and storage demand charges, which are based on contracted quantities and do not fluctuate based on actual usage, the midstream rate is relatively more stable than the commodity rate. The midstream component costs are captured within the Midstream Cost Reconciliation Account (MCRA).

The delivery charge components include the delivery rate and the fixed basic charge. These relate to the costs for FEI to move the commodity and midstream supply on FEI's transmission and distribution systems to FEI's customers. The delivery margin is typically set annually in accordance with Revenue Requirements Application decisions.

The following figure shows the current breakdown of the components of the FEI residential rate, on a per unit basis, effective October 1, 2014.[25]

[23] Based on FEI Lower Mainland residential rates effective October 1, 2014.
[24] Per the FEI 2013/2014 Annual Contracting Plan dated May 1, 2013.
[25] The per unit fixed basic charge is based on 95 GJ/year of consumption.

Figure 4-7: FEI Residential Rate Components Effective October 1, 2014



4.4.2 Rate Setting

The commodity and midstream rates are determined by forecasting costs for the next twelve months and comparing them to existing rates. FEI's commodity rates are reviewed each quarter while midstream rates are reviewed annually. For the commodity rate, this primarily includes applying forward market prices to projected annual load volumes and then adjusting for any accumulated surplus or deficit deferral balances (gas cost deferral accounts are described in the next section). If the projected commodity rate is within the +/- 5 percent deadband threshold (i.e. the projected commodity rate is not 5 percent higher or lower than the current commodity rate) and also within the +/- $0.50/GJ deadband threshold (i.e. the projected commodity rate is not $0.50/GJ higher or lower than the current commodity rate), then the commodity rate is left unchanged. This helps to manage deferral account balances to an appropriate level and reduces the likelihood of frequent rate changes in a relatively low commodity price environment.

The midstream rate is determined by estimating storage and transportation demand charges, storage injections and withdrawals and gas supply purchases and forecast gas resale quantities for the next twelve months. Accumulated deferral balances are also included in forecast midstream costs when determining the midstream rate. The midstream rate is reset each calendar year. Deferral account balances for the MCRA are typically not as large as the CCRA deferral balances, even though the midstream rate is changed only once per year, as the MCRA is comprised largely of more predictable fixed transportation and storage demand charges rather than market-priced purchases.

In 2011, as a result of a Commission directed review, FEI proposed minor changes to the Commission guidelines for setting gas cost recovery rates and managing the gas cost deferral account balances (the Guidelines), as originally established pursuit to Commission Letter L-5-01 dated February 5, 2001. The minor changes proposed by FEI were designed to reduce the potential frequency of minor rate changes, particularly in low price environments for natural gas. The Commission Letter L-40-11, issued on May 19, 2011, provided approval for the revisions to the Guidelines. Those revisions included:

- Natural Gas Commodity Price Forecasts – Adoption of a five-day average of forward prices taken on consecutive market dates.
- CCRA Deferral Account and Rate Adjustment Mechanism – The CCRA rate change trigger mechanism will be the ± 5 percent trigger ratio plus a minimum rate change threshold of ± $0.50/GJ.
- MCRA Deferral Account and Rate Adjustment Mechanism – One-third of the cumulative MCRA deferral balance at the end of each year will be amortized into the next year's midstream rates.

In its natural gas price forecasts, FEI adopted using a five-day average of forward prices rather than relying on a single day's forward prices. This has helped to reduce some of the price variability in the gas cost forecasts as there can be significant swings in daily spot market prices.

A minimum rate change threshold of ±$0.50/GJ was added to the ± 5 percent trigger ratio in determining CCRA rate changes. This has helped to reduce the number of minor rate changes that would have otherwise occurred in the current low market price environment. For example, based on FEI's January 1, 2013 CCRA rate of $2.977/GJ, a CCRA rate change could be triggered by only a $0.15/GJ increase or decrease in forecast gas costs. However, by adding the ±$0.50/GJ threshold, such relatively minor rate changes are reduced, providing more rate stability for customers.

In order to provide more stability to the MCRA rate, it was determined that one-third of the cumulative deferral balances at the end of each year would be amortized into next year's MCRA rates. Prior to this change, all of the cumulative deferral balances at the end of each year were amortized into the following year's MCRA rates. This resulted in larger changes in MCRA rates from year to year, often leading to over-collection in one year and under-collection in the next. More recently, however, in order to comply with U.S. Generally Accepted Accounting Principles (US GAAP) for financial reporting, FEI has proposed within its June 10, 2013 Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 (PBR) to amortize one half of the cumulative deferral balances at the end of each year into next year's

MCRA rates effective January 1, 2014. This change was accepted by the Commission in its PBR decision dated September 15, 2014[26].

In the Commission's letter approving the revised Guidelines, the Commission stated that it agrees with FEI that the Guidelines are intended to be applied in a flexible manner, considering the full circumstances prevailing at the time when a quarterly report is under review. As well as the Guideline trigger mechanism and rate methodology, consideration should be given to factors such as the current deferral balances and, based on the forecast costs, the appropriateness of any rate proposals over a twenty four month timeframe.

4.4.3 Gas Cost Deferral Accounts

Gas cost deferral accounts and recovery mechanisms are used to effectively manage, through rates, the recovery of incurred gas costs from customers. Since gas cost rates are based on forecast costs and actual costs invariably differ from forecast costs, the gas cost deferral account mechanisms essentially capture the differences between the actual gas costs incurred and the revenues collected through gas cost recovery rates, with these resultant deferral balances to be recovered from, or refunded to, customers through future rates. In this way deferral accounts provide some rate stability by deferring the impact of commodity market volatility on gas costs. When setting commodity rates, CCRA deferral account balances are typically amortized over the next twelve months, providing a shorter term impact on rate volatility. However, it is important to note that deferral account balances do not impact underlying market gas prices which determine rates. Furthermore, as discussed below and in Section 5.2, it is prudent to manage deferral account balances to appropriate levels. Therefore, they are limited in their ability to mitigate market price risk, particularly during periods of market price volatility or rising market prices over time.

The gas cost deferral account recovery mechanism has evolved over time as the natural gas marketplace has changed. Prior to 1999, the gas cost recovery rates for FEI were established once per year, based on the forecast costs for the upcoming year and using a January 1st effective date. As a result of changing natural gas fundamentals, which increased market price volatility, FEI incurred much higher gas costs during 1999 and 2000 than forecast, and so mid-year increases to gas cost recovery rates were requested by FEI to reduce the significant under-recovery of gas costs. And, even with the mid-year gas cost recovery rate increases, the gas cost deferral account changed from a net surplus balance (gas cost recovery revenues exceeded gas costs incurred) to a net deficit balance (related costs exceeded gas cost recovery revenues) of approximately $180 million by the end of 2000.

Significant deferral account deficits can impact FEI's borrowing capacity, risk profile and potentially influence credit ratings. Depending on when they are recovered, large deficits or surpluses can also create intergenerational inequities.

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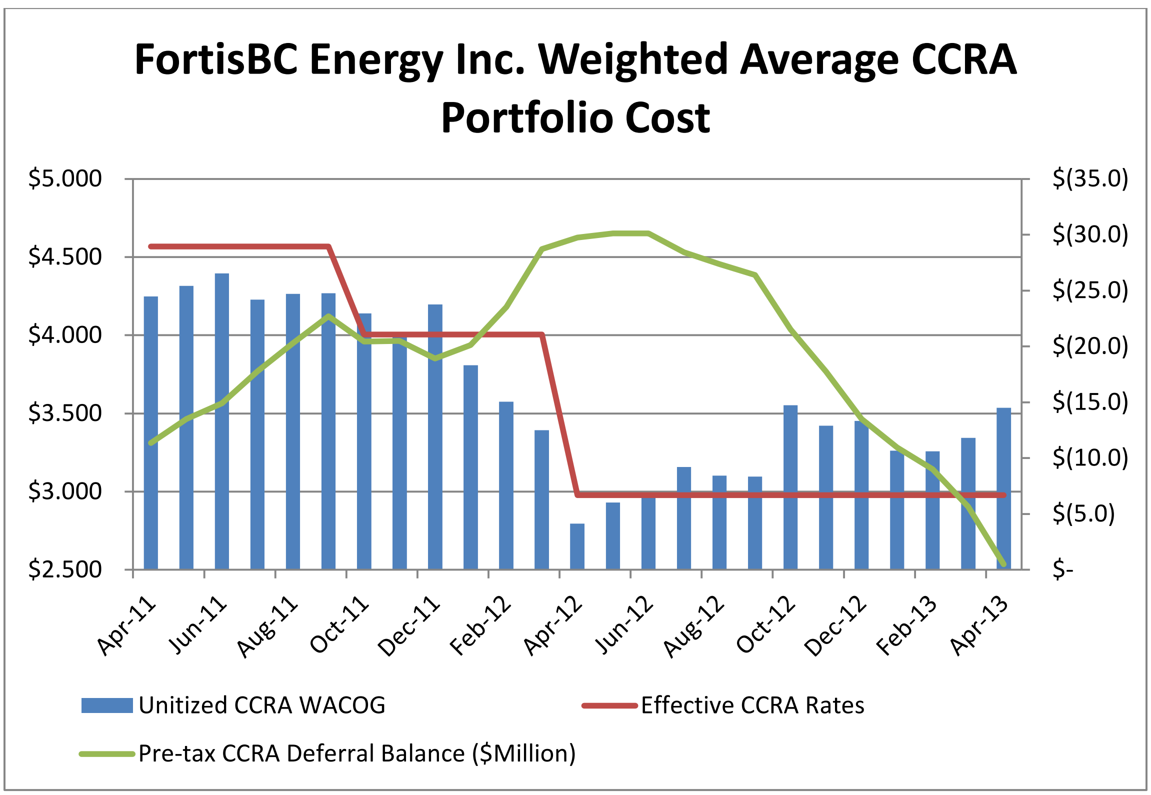
[26] FEI Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018, Commission Decision, September 15, 2014, page 234.

Currently, FEI uses a quarterly rate adjustment review mechanism to effectively manage the deferral account balances from becoming too large, as well as providing appropriate price signals regarding market gas prices to customers. The CCRA became effective April 1, 2004 and since that time deferral account balances, on a net of tax basis, have generally been within a reasonable ± $50 million range. The quarterly review and opportunity to adjust deferral account balances provides timely management of these balances to an appropriate amount. This is in the best interests of customers, in terms of rate volatility mitigation, price transparency and reduced intergenerational inequities and allows for prudent financial management by FEI.

The following figure illustrates how the CCRA rate setting and deferral account balance mechanism work using historical information. During 2012, as market gas prices fell below actual CCRA rates, the deferral account balance surplus continued to grow until it peaked near $30 million in mid-2012 when gas prices fell to their lowest level in a decade. Based on this accumulated deferral surplus balance and lower projected gas costs, FEI reduced its commodity rate to $2.977/GJ effective April 1, 2012. After that time, market prices rebounded to levels above the CCRA rate and the deferral account surplus eroded until it reached zero by mid-2013.

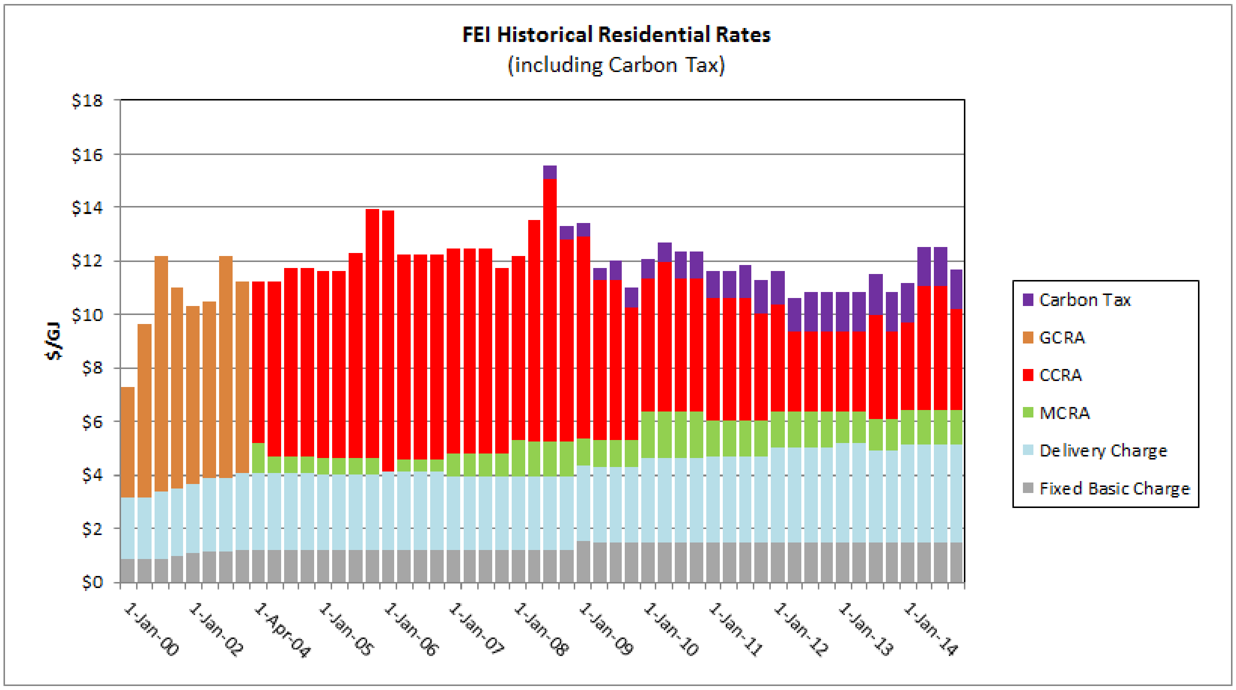
Figure 4-8: Historical FEI CCRA Rate and Deferral Account Balance



4.4.4 FEI Historical Rates

The following graph shows the FEI historical and current residential rates effective October 1, 2014 on a per unit basis. The carbon tax on natural gas, approximately equal to \$1.50/GJ[27] effective July 1, 2012, has been added to the FEI rates in the graph. Prior to the start of commodity unbundling in April 2004, the CCRA and MCRA components of the bill were combined within the Gas Cost Reconciliation Account (GCRA).

Figure 4-9: FEI Historical Residential Rates Plus Carbon Tax



The figure shows that the FEI total rate (excluding carbon tax) had shifted downwards with market prices since the middle of 2008 and during 2012 was at its lowest level since July 2000. However, with the recent market price increases and volatility, there has been more volatility in commodity rates. On April 1, 2014, FEI increased its commodity rate by \$1.37/GJ, its largest commodity rate increase since 2008. This rate increase put the FEI commodity rate of \$4.64/GJ above recent historical averages. On October 1, 2014, FEI decreased its commodity rate to \$3.78/GJ. For comparison, the most recent five-year historical average FEI commodity rate is about \$4.08/GJ.

4.5 *CURRENT OPTIONAL PRODUCTS FOR CUSTOMERS*

The following section provides a discussion of the optional products currently available to gas customers to help manage their rate or bill volatility. This includes the fixed rate offerings

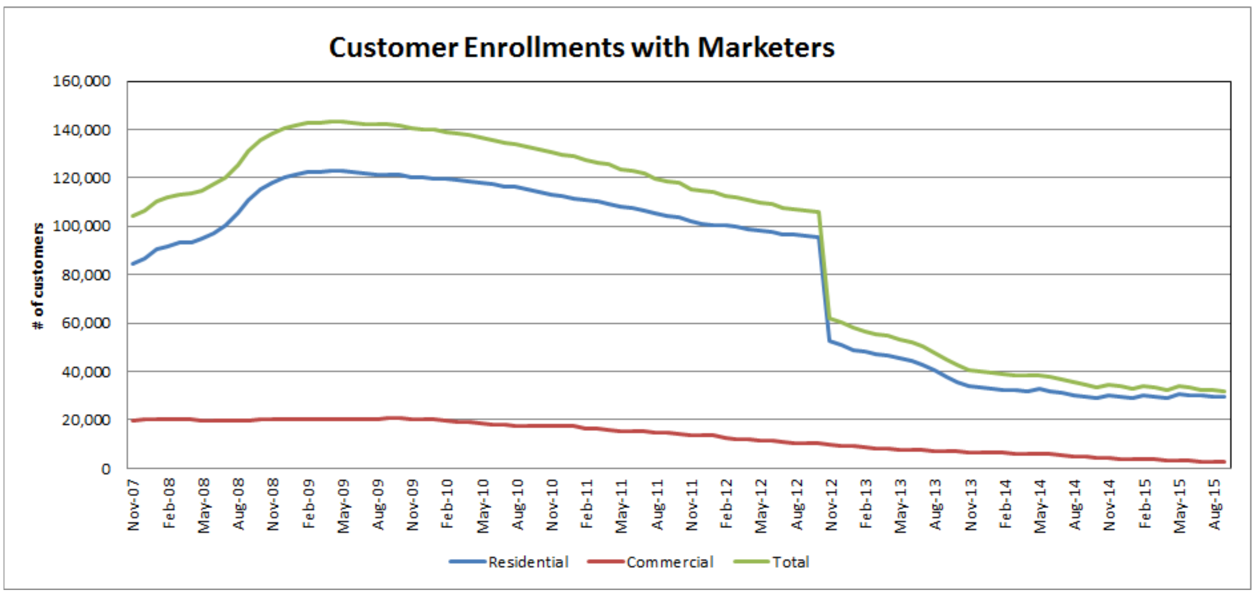
[27] Based on \$30 per tonne of CO2 equivalent emissions.

currently provided by gas marketers to residential and commercial customers under the Customer Choice Program. It also includes the Equal Payment Plan.

4.5.1 Fixed Rate Offerings under the Customer Choice Program

FEI residential and commercial customers (rate classes 1, 2 and 3) can currently enter into fixed rate commodity supply offerings for terms up to five years with natural gas marketers under the Customer Choice program. The following figure shows the historical customer enrollments with natural gas marketers since the inception of the residential service offerings effective November 1, 2007 as well as the projection of enrollments based on recent contracts. The large drop in November 2012 is due to the expiry of five-year contracts which began in November 2007, when the program was first opened up to residential customers, after which time customers migrated back to the FEI default commodity offering.

Figure 4-10: Customer Choice Enrollments with Natural Gas Marketers



It should be noted that, at this point in time, overall customer enrollments with natural gas marketers' offerings are at their lowest point since the Customer Choice program began. Currently, enrollments with natural gas marketers are less than 5 percent of the eligible number of customers. Therefore, the vast majority of customers are paying the FEI default commodity rate for their natural gas.

As the research discussed in Section 7.1.2 indicates, customers are wary of natural gas marketers' offerings and being locked into higher rates than the market. Many customers enrolled with natural gas marketers were not able to participate in the significant decline in market prices between 2008 and 2012 as they were locked into contracts up to five years in length. The following table shows the latest gas marketers' fixed rate offerings compared to the forward market prices (weighted 75 percent Station 2 and 25 percent AECO/NIT) as of October 1, 2014. The current FEI commodity rate is $3.78/GJ.

Table 4-2: Natural Gas Marketers' Fixed Rate Offerings[28] and Forward Market Prices[29]

Term	Number of Marketers	Fixed Rate ($/GJ)	Forward Market Price ($/GJ)
1 Year	1	$4.89 - $6.14	$3.71
2 Year	1	$5.89 - $6.89	$3.69
3 Year	3	$4.99 - $6.89	$3.70
4 Year	3	$5.85 - $7.49	$3.74
5 Year	5	$4.89 - $7.49	$3.80

4.5.2 Equal Payment Plan

The Equal Payment Plan is an option for customers looking to smooth out their monthly bill payments. Customers' consumption and commodity rates are forecast in order to average out the next twelve months' bills. However, during periods of volatile rates and/or higher or lower expected consumption, periodic adjustments may be required within the twelve month period. This is to prevent large adjustments for EPP customers at the end of the twelve month term. Currently, about one third of customers are signed up for the EPP.

While the EPP acts to smooth customers' bills by averaging consumption, it does not affect underlying gas prices like other price risk management tools, such as hedging or long term fixed price purchases. Furthermore, under the EPP, the equal twelve month payment instalments are reviewed every three months and adjusted if necessary to reflect changes in weather, gas usage or gas rates. This is done to avoid significant billing adjustments at year end caused by large changes in weather related consumption or quarterly rates. So, during periods of extremely volatile market prices and subsequent quarterly rate changes, EPP customers may also be subject to quarterly, rather than annual, rate changes. As such, FEI believes that the EPP is not a substitute for other forms of price risk management, such as hedging, but rather should be included as part of a portfolio approach in reducing rate and bill volatility for customers. Gaz Métro has a similar view regarding equal payment plans, particularly during a period of rising prices: "[The Equal Payment Method] does not reduce the impact of an increase in natural gas prices. It only postpones the increase until the end of the equal payment period. The volatility calculated over a longer period than for the equal period method is not absent. In addition, in the case of significant variations from the price forecasts or to the consumption profile, a re-evaluation of the monthly amount to be billed can be made during the year in progress."[30]

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28 http://www.fortisbc.com/NaturalGas/Homes/CustomerChoice/ComparingHowRatesAreSet/PriceComparison/Pages/default.aspx - Oct. 1, 2014

29 Forward prices as of Oct. 1, 2014

30 Gaz Metro Proposals for a Financial Derivatives Program, page 38, provided in Appendix G

5. PRICE RISK MANAGEMENT ALTERNATIVES

There are a number of available alternatives that are being considered by FEI in managing price risk for customers. FEI provides an assessment of these alternatives in this section. The alternatives are based on consideration of what is available to FEI in the marketplace, the market price environment, customer research and recommendations from Aether. They also take into account direction from the Panel decision. They include physical tools, such as the use of storage or longer term tools like fixed price purchases or VPPs, the use of deferral accounts and rate setting mechanisms and financial hedging instruments. On an optional basis for customers, the Equal Payment Plan and Customer Choice program will continue to offer ways for customers to smooth out their monthly bills or enter into fixed rate contracts with natural gas marketers. These instruments, tools and mechanisms should be considered as part of an overall price risk management strategy and they all work differently, with no single one effectively meeting the objectives on its own. As part of the assessment of alternatives for managing price risk, FEI also considered optional rate offerings for customers. A discussion of this is provided in Section 7.

5.1 *PHYSICAL RESOURCES AND STRATEGIES*

The ACP includes physical strategies and resources to help ensure cost effective and reliable supply and also manage market price volatility. The ACP is submitted to the Commission for acceptance on an annual basis and has the following objectives:

1. To contract for resources which ensure an appropriate balance of cost minimization, security, diversity and reliability of gas supply in order to meet the core customer design peak day and annual requirements.
2. To develop a portfolio mix which incorporates flexibility in the contracting of resources based on short term and long term planning, and evolving market dynamics.

The ACP includes the portfolio of physical supply, transportation and storage resources to meet customers' load requirements. The portfolio provides supply hub and market price diversity to reduce the risks of supply disruption or the impacts of price spikes at a particular market hub. It also includes the use of storage resources which provide resource flexibility and effective load management as well as summer-priced supply for the peak winter demand. Longer term resources include multi-year storage and transportation contracts and supply arrangements. The following sections describe the physical tools that can be used to manage price risk, as well as provide security of supply, for the short term, medium term and longer term.

5.1.1 Storage Resources

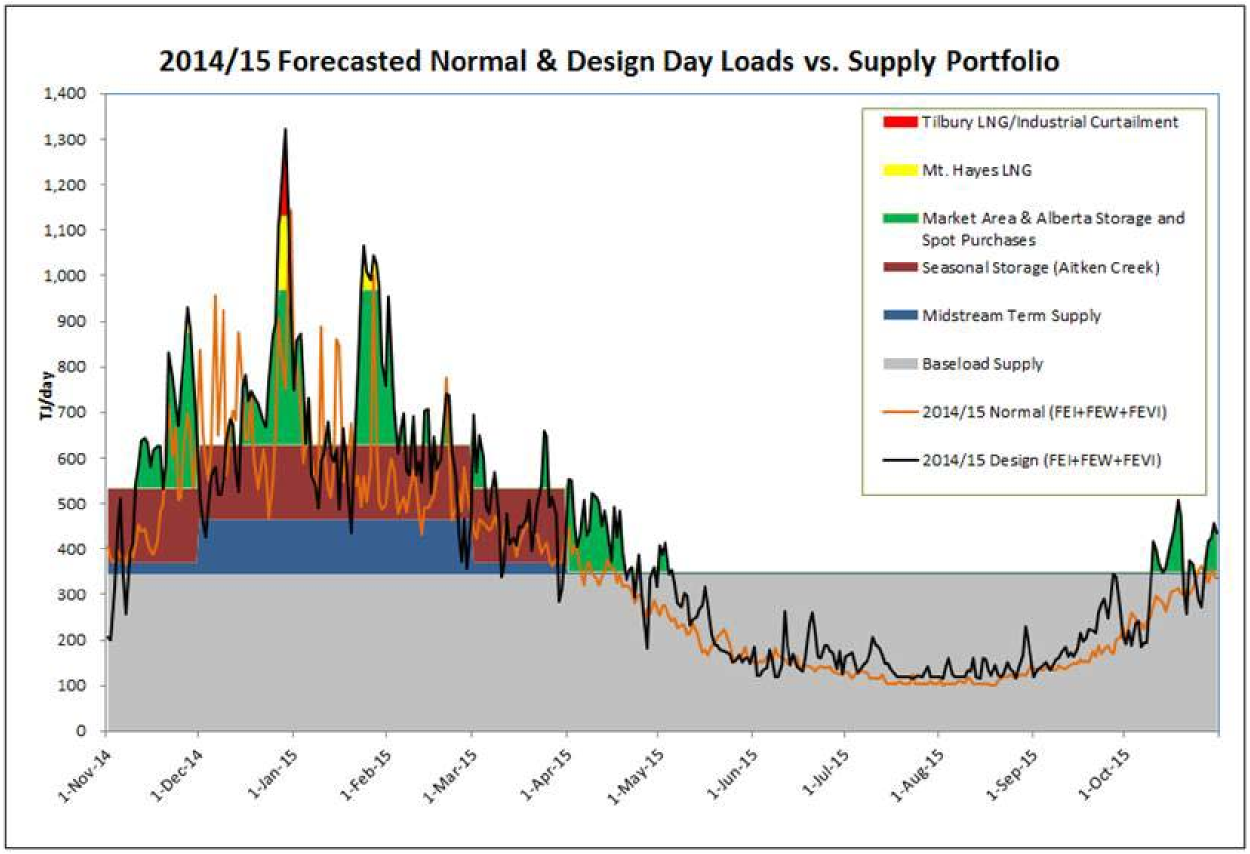
An effective tool for mitigating short term market price risk is the use of natural gas storage. When evaluating storage it is important to consider its value, limitations and availability. FEI uses storage within its portfolios to meet normal winter and peak load requirements for core customers. The following section describes the value of storage for FEI in meeting the objectives of the ACP and price risk management.

5.1.1.1 The Value of Storage

Storage provides both operational and financial value. Storage, with associated transportation service, enables FEI to meet normal and peak winter demand and generally enables the use of lower priced summer gas for winter demand, effectively acting as a "natural hedge". Operational benefits can include flexibility for imbalance management (i.e. to meet third party pipeline daily or monthly volumetric balancing requirements), supply curtailment or disruption mitigation and balancing intra-day load variability. The primary financial benefit includes seasonal price protection (i.e. capturing the price differential between winter and the previous summer) which serves to protect customers from any adverse price movements in the winter period.

Storage plays an important role in meeting the objectives of the ACP. Rather than securing additional seasonal winter supply to meet above-normal loads, FEI utilizes storage resources to better shape resources to the load profile. This is more cost effective, by reducing the requirement to sell off excess supply at a possible loss and using summer priced gas, and also provides diversity in the portfolio. The following graph shows how the storage resources fit within the overall portfolio (using the planned portfolio per the 2014/15 ACP as an example), providing supply to meet the higher loads during the winter months. While seasonal storage, such as Aitken Creek in northern B.C., is typically used for most of the days in the winter period, market area storage, such as Mist or Jackson Prairie in the U.S., has a shorter duration profile and so is reserved for the colder days of the winter.

Figure 5-1: FEI Forecast Loads vs. Resource Portfolio



The use of storage also reduces the portfolio exposure to regional price disconnections such as Sumas price spikes during periods of high regional demand.

5.1.1.2 Limitations of Storage

While storage does provide both financial and operational value, it also has some limitations. In terms of reducing winter price exposure, the seasonal price protection is generally limited primarily to a single winter period due to the necessity to cycle most or all of the storage volumes on an annual basis to effectively meet load requirements. As such, it does not provide the longer term (i.e. greater than single winter season) price protection like that of financial hedging or longer term fixed price purchases. Additionally, while storage enables capturing summer prices for winter demand, it does not provide summer period price protection in the event that hurricane disruptions or above normal summer temperatures and gas demand raise summer prices. For example, during August and September 2005, market prices spiked in response to the disruption to gas production facilities in the Gulf of Mexico caused by hurricanes Katrina and Rita (see Figure 4-4). Financial hedging and longer term fixed price purchases do provide this year-round longer term market price protection. Storage resources should be included in the portfolio of tools and strategies to manage price risk.

5.1.1.3 Storage within the 2014/15 ACP

The ACP is developed with consideration of the available storage resources for the gas supply portfolio. Availability, cost effectiveness and flexibility are all considered when contracting for storage resources and these attributes can change from time to time as market place developments occur. The 2014/15 ACP includes a description of storage and resource contracting as well as the contracting of any new, or the renewal of existing, agreements. Given the decline in market gas prices and narrowing of summer and winter price spreads compared to recent historical values, FEI has assessed its storage resources and considered more storage capacity and longer terms. For example, FEI renewed an expiring portion of its Aitken Creek storage capacity in 2013 for a ten year term[31]. More recently, FEI requested Commission approval to contract for incremental Aitken Creek storage capacity effective April 1, 2014 as more storage capacity, plus associated transportation capacity, became available. Incremental Aitken Creek storage capacity had not been available until recently. The Commission accepted this request with Order E-11-14 dated May 8, 2014. These storage agreements will provide longer term security of supply within the FEI portfolio, which is important given the changes occurring in northern B.C. in terms of expected supply and demand growth and potential infrastructure developments (see Appendix B for more details).

FEI will continue to monitor forward market price spreads and storage costs and seek opportunities to provide operational and financial value to customers as outlined within the ACP.

5.1.2 Receipt Point Allocation Change

FEI also helps mitigate market price volatility and possible supply disruptions by sourcing its gas supply from several different market supply hubs as defined within the ACP. In the past, FEI has sourced commodity supply according to the following allocation: 70 percent Station 2, 15 percent AECO/NIT and 15 percent Huntingdon. This allocation has provided some diversity within the portfolio but does include high reliance on Station 2 supply and Spectra's T-South pipeline system to bring gas to customers due to the limited regional resources available to FEI. As discussed within the 2013/14 ACP, FEI expressed its concerns with the reduction in recent T-South firm service contracting levels and the reliability of Huntingdon supply going forward. As such, FEI reduced its exposure to Huntingdon supply and changed the commodity supply receipt point allocations within the 2013/14 ACP to the following percentages effective November 1, 2013: 75 percent Station 2 and 25 percent AECO/NIT. As discussed within Section 4.2.4, Sumas prices at the Huntingdon market hub have traded well above Station 2 and AECO/NIT prices this past winter, with significant Sumas price spikes occurring during December 2013 and February 2014. This receipt point allocation change has mitigated the impact of these price spikes on FEI's commodity costs for customers and improved portfolio reliability by reducing exposure to Sumas pricing. FEI will continue to monitor developments at Huntingdon and the levels of T-South contracting in the interest of meeting the objectives of the ACP.

[31] On April 3, 2013, FEI submitted a request to the Commission to replace expiring Aitken Creek storage capacity with a ten year firm gas storage agreement. This was accepted per Commission Order E-5-13 dated April 18, 2013.

In the past, FEI has used winter Sumas-AECO/NIT basis swaps to mitigate Sumas price risk. These financial instruments involve locking in the price difference, or basis, between Sumas and AECO/NIT prices but not locking in the underlying Sumas or AECO/NIT prices themselves. These instruments proved to be cost effective during the years they were implemented by FEI[32] and were accepted by the Commission as "a cost effective strategy in mitigating the impacts of Sumas price volatility for customers"[33] and as part of the Review decision.[34] The last period for which FEI implemented the basis hedges was for winter 2012/13 due to the receipt point allocation change effective winter 2013/14. FEI will continue to consider the use of Sumas-AECO/NIT basis swaps if it is not able to eliminate Huntingdon supply within the ACP.

5.1.3 Long Term Fixed Price Purchases

The commodity gas purchases within the ACP are currently generally based on index pricing at the Station 2 and AECO/NIT market hubs, which is subject to the price volatility of the natural gas market. An alternative for mitigating this market price volatility over the longer term is using long term (i.e. up to ten years) fixed price purchases, where the purchase price is locked in at a point in time and does not change for the contract term. Purchasing longer term fixed price supply would be consistent with the Panel's directives in the Review in terms of mitigating longer periods of persistent volatility. It would also provide security of supply, an important objective of the ACP. Long term purchases at the Station 2 market hub, whether fixed price or market-based, would help promote the development of gas production in northern B.C. for end use markets further south, including FEI's customers, and improve liquidity at Station 2. This security of supply is important given the developments occurring in northern B.C. where pipeline initiatives by TransCanada Pipelines Limited (TCPL) and LNG export proposals will provide gas producers with more markets for their production (see Appendix B).

FEI understands some producers may be willing to sell gas supplies at fixed prices in order to provide diversity from index prices or potential market price fluctuations in the future. Given the relatively low price environment, it may be a favourable time for gas buyers, such as FEI, to enter into such arrangements with suppliers. Forward market prices for five years out currently average about $3.70/GJ for Station 2 supply[35]. This price level is below FEI's commodity rate of $3.78/GJ effective October 1, 2014 and the historical five-year average of FEI commodity rates of $4.08/GJ. This may be an opportunity for FEI to lock in favourable prices.

As these types of supply arrangements are not commonplace in the market, there is uncertainty regarding how many suppliers may be willing to transact. FEI has already been in contact with a number of suppliers regarding fixed price purchases in order to determine interest. While some have indicated that they are not interested in selling at fixed prices, given the low price environment and uncertainty regarding drilling plans, others have expressed interest in order to diversify their portfolios. However, there is also uncertainty regarding the potential supply and

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[32] Total basis swaps cost for 2001 to 2013 was $4.7 million, or less than 1% of total gas portfolio costs of $5.4 billion.
[33] The Commission accepted the FEI basis swaps request for winter 2012/13 per Letter L-40-12 dated July 13, 2012.
[34] Commission Order G-120-11, Appendix A, page 23.
[35] Based on forward market prices as of Oct 1, 2014.

demand for natural gas in B.C. due to the proposed LNG export projects. Some suppliers may want greater certainty regarding LNG project final investment decisions or charge a premium for this uncertainty before committing to a longer term deal.

It is also possible that some producers may want to sell fixed price supply at the plant outlet, upstream of Station 2. FEI would be willing to purchase at plant outlets provided T-North transportation required to move gas south is available and FEI is able to negotiate favourable pricing that offsets any incremental transportation required.

Locking in long term market prices could also be done financially with hedges. However, FEI believes that long term physical purchases are likely easier to transact for both parties than long term financial hedges, particularly beyond five years, because of counterparty credit exposure consideration. This usually requires special contract provisions or contract amendments relating to additional collateral requirements in order to protect each party in the event of payment default. With physical purchases, on the other hand, FEI would be buying gas directly from the producer and so the producer would be relying on FEI's creditworthiness. This would likely not be a significant concern for most producers that view FEI as an attractive credit-worthy counterparty and the fact that FEI would seek Commission approval, ensuring recovery of costs in rates from customers, before entering into any long term deals. Therefore, while financial hedges are a good medium term tool (i.e. up to five years), physical fixed price purchases are likely a better longer term tool (i.e. beyond five years).

FEI believes that this type of supply arrangement helps manage potential longer term periods of higher prices or persistent volatility that could occur in the future and therefore is consistent with the Panel's decision recommendations. It also provides security of supply, helping meet the objectives of the ACP. It is also consistent with Aether's recommendation that FEI consider longer term fixed price purchases, as discussed in Section 8.

5.1.4 Investment in Natural Gas Reserves

Another alternative for managing even longer term market price increases or volatility is investment in natural gas reserves. This would also help promote gas production development in B.C. and provide security of supply, a primary objective of the ACP, which is important given the developments occurring in northeast B.C.

FEI has investigated, at a high level, the potential for investing in physical gas reserves. In this type of arrangement, the buyer would invest in reserves by entering into a joint venture with a gas producer for a term up to thirty years. The buyer would share in the cost of developing and producing the gas and earn the right to a portion of the production.

An example involving a natural gas utility is the joint venture arrangement between Encana Corporation (Encana) and NWN effective May 1, 2011 to develop natural gas reserves in Encana's Jonah Field in Wyoming. Under the initial terms of the agreement with Encana, NWN pays approximately $45 to $55 million a year, for a five-year period, for a total investment of about $250 million, which will cover expected drilling costs in exchange for working interests in certain sections of the Jonah Field. Over the thirty-year life of the investment, NWN expects to receive approximately 93 billion cubic feet (Bcf) of gas at an average all-in cost of approximately $5.15 per dekatherm (the equivalent of about $5.40/GJ). The anticipated net present value savings to its customers, based on forward market prices at the time of the deal, were expected to be more than $50 million over the life of the investment[36]. The Oregon Public Utility Commission (OPUC) approved the arrangement as being in the interests of customers. In this business model, a joint venture was established between Encana and the NWN, where Encana contributed land, infrastructure, and drilling and operating expertise and NWN contributed higher up front capital for the drilling and completion of wells. When the drilling program is completed, Encana and NWN share in the resulting gas production for the life of the reserves. The gas reserves effectively provide a hedge on approximately ten percent of NWN's gas supply portfolio. At the time, the President and CEO of NWN stated: "We believe locking in a portion of our supply with lower cost gas is the right thing to pursue on behalf of our customers".[37] Recently, Encana announced that it had divested its interests in the Jonah Field to an affiliate of TPG Capital (TGP). The new partnership with TGP increases NWN's interests in sections of the Jonah Field and provides the opportunity to develop future reserves. NWN recently stated: "Encana was a great company to partner with on this innovative agreement, and we look forward to working with the new owner and the OPUC to explore the potential benefits of further well development at Jonah."[38]

FEI has met with producers to discuss pursuing similar arrangements based on B.C. or Alberta production. Under the right type of joint venture transaction, the potential benefits to FEI would include obtaining gas supply on a cost basis, reduced exposure to market price volatility, physical supply diversity and long term security of supply. The benefits for the producer include the access to third party capital to carry-on with drilling programs or to develop higher cost or marginal gas plays.

In terms of rate setting and the accounting treatment of reserves, FEI would expect that any capital investment would be included in rate base upon which the utility would earn a rate of return. Capital, operating and drilling costs would be included in the CCRA and recovered like the costs for other sources of commodity supply.

Managing the risk associated with reserves would be of paramount importance to FEI in a reserves arrangement. While it may seem that the risk associated with drilling, completing, and operating wells would differ from typical regulated utility assets, FEI believes there may be ways to mitigate these risks through contractual arrangements and effective due diligence. One important feature of any deal would be the ability to transfer risks to producers that are appropriate for a producer to manage, such as drilling risks and most operating risk. Ultimately, any transaction would require some degree of cost certainty for the longer term.

[36] http://www.businesswire.com/news/home/20110429005599/en/Oregon-Utility-Commission-Approves-NW-Natural-Encana

[37] http://www.marketwired.com/press-release/nw-natural-renegotiates-joint-venture-with-encana-oil-gas-nyse-nwn-1894135.htm

[38] http://www.marketwired.com/press-release/nw-natural-renegotiates-joint-venture-with-encana-oil-gas-nyse-nwn-1894135.htm

This type of transaction would not provide the same degree of price certainty as a hedging or fixed price purchase strategy but would provide cost based supply for a longer period of time.

At this time, under the current market environment, longer term arrangements, such as investing in reserves, may be difficult to transact. This is because of the uncertainty with regard to potential market developments, such as B.C. LNG exports and the development of B.C. gas production.

Appendix C of Aether's review report discusses this and other arrangements regarding utilities investing in natural gas reserves. While Aether does recommend FEI consider longer term price risk management alternatives, such as investing in natural gas reserves, Aether suggests that long term fixed price purchases and VPPs might better suit FEI's risk profile and field of expertise. FEI agrees with this view.

5.1.5 Volumetric Production Payment

Another tool for managing longer term price risk is a volumetric production payment. In this arrangement, the buyer pays an upfront lump sum payment to gas producer in exchange for specific volumes delivered over the term of the agreement (up to twenty years). The buyer also receives a limited royalty interest in the production volumes which is returned to the seller once the volumes have been delivered. As with investment in reserves, gas producers will use these types of arrangements to help finance new exploration and production.

VPP arrangements provide greater volume certainty than investment in reserves. The VPP is a firm delivery contract whereas investing in reserves provides the buyer an operating interest in a portion of the production. Therefore, a VPP typically has less production risk than an investment in gas reserves. However, investment in reserves does provide for the potential for increased value of the production in a rising gas price environment. Part VII of Aether's report includes a more detailed discussion of the pros and cons of these longer term price risk management tools. As mentioned, Aether suggests that VPPs would provide FEI with longer term cost certainty and security of supply and help meet the price risk management objectives.

As with investing in reserves, under the current market environment, longer term arrangements, such as VPPs, may be difficult to transact. At this time, FEI has not had any discussions with gas producers regarding VPPs and has only investigated these arrangements at a high level. Therefore, FEI could further investigate VPPs and monitor market developments to see if these types of arrangements are viable as part of a longer term strategy.

5.2 *THE ROLE OF DEFERRAL ACCOUNTS AND QUARTERLY RATE SETTING IN PRICE RISK MANAGEMENT*

Deferral accounts and the quarterly rate setting mechanism provide some degree of price risk management during periods of relatively stable market prices. However, as described below, they are not as effective during periods of high market price volatility or sustained market price increases.

Deferral accounts do not reduce market price volatility in the same way as financial hedging or physical fixed price purchases. These instruments directly impact gas costs by locking in gas prices rather than deferring actual gas costs to a later time. Therefore, they reduce market price risk as well as rate volatility. RiskCentrix offered the following comments regarding the use of deferral accounts: "Generally deferrals do not serve as an alternative to an effective hedging program. A short-duration deferral mechanism adds modest additional stability when used in conjunction with a robust hedge program; it is inferior as a stand-alone approach in the absence of a hedge program." "The risk of deferral accounting is that deferrals could accumulate to unsustainable levels resulting in the need to ultimately pass through more radical costs."[39] Ruben Moreno of Concentric provides a similar view in his review of Gaz Metro's Financial Derivatives Progam, which is provided in Appendix I:

> *"Though I agree that in periods of low volatility and declining prices this [deferral accounts and rate setting mechanisms] may be all that is required to minimize the effect of price increases, there is nothing to protect the customer from extreme and sustained price increases. The customer will eventually pay for the price increase. The deferral accounts or purchased gas adjustments largely create a cosmetic effect on prices by simply averaging the price spikes over a longer period of time. By the same virtue, the averaging of the spike also creates a form of stickiness in prices because the effect of the price spike tends to be longer-lived. Hedging strategies are more successful if they are structured to avoid the spikes instead of just smoothing the effect."*[40]

In addition, deferral accounts, if significant in value, can impact the utility's borrowing capacity, thereby harming cash flow and credit rating. Aether comments: "The use of deferral accounts provides utilities and their investors with a degree of comfort that potentially uncertain commodity costs will be recovered. However, an accumulation of large deferral balances can create credit and liquidity concerns. For instance, credit rating agencies tend to view very large deferral balances negatively out of concern that subsequent recovery may not fully occur." "…long-term deferral of costs can produce an illusion of stability when large increases follow, potentially surprising customers."[41] In its review of the FEI hedging program, the Panel offered the following comment: "…the Panel acknowledges that while deferral accounts provide some smoothing, they do not affect or help manage the underlying commodity prices".[42] This is illustrated in Aether's report provided in Appendix G on page 30, Figure 11, which clearly demonstrates the limited ability of deferral accounts to mitigate longer term increases in market prices. Therefore, deferral accounts should not be counted on alone for effective price risk management, especially beyond the short term. They do, however, provide some degree of rate volatility protection, and so should be considered along with other forms of price risk management in a portfolio approach to meet the objectives.

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[39] RiskCentrix, Findings and Recommendations Regarding Energy Risk Mitigation Program prepared for Terasen Gas, December 27, 2010.

[40] Concentric's Assessment of Gaz Metro's Financial Derivatives Program, September 26, 2013, page 18.

[41] Aether Advisors LLC, Review of FortisBC Energy Inc. Price Risk Management Strategies and Tools, February 2014, page 29.

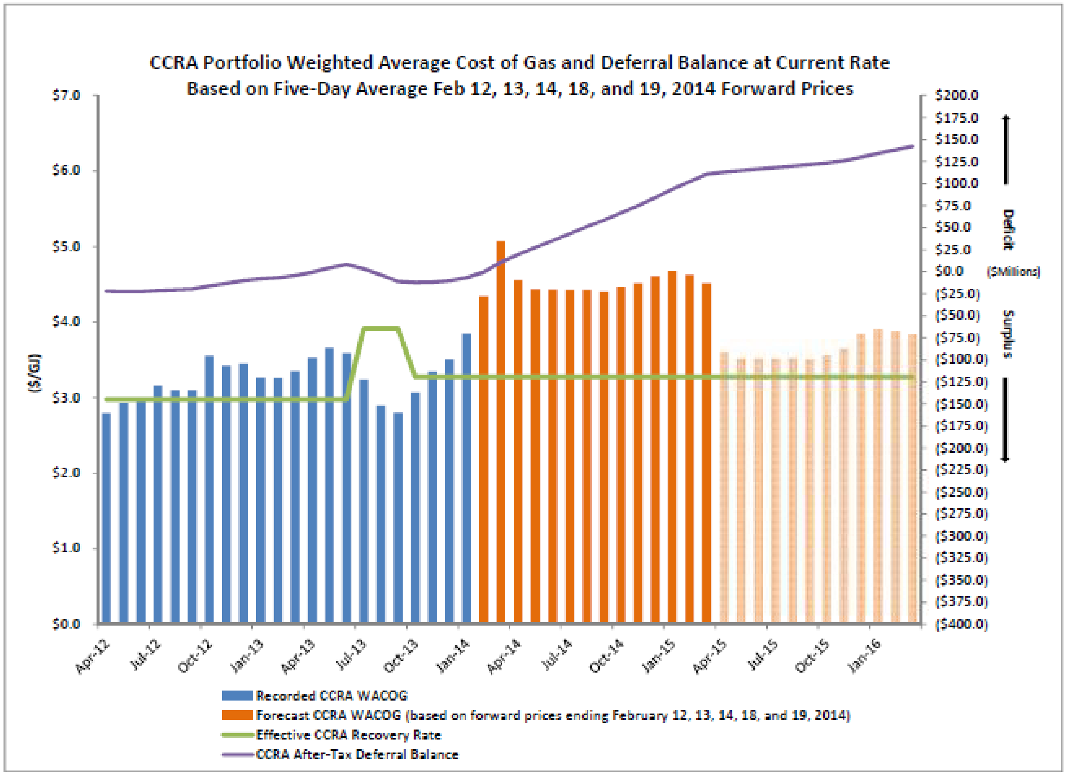
[42] Commission Order G-120-11, Appendix A, page 24.

Amortizing any accumulated deferral account balances and projected gas costs over a longer period of time to help mitigate rate volatility should be considered when setting commodity rates. For example, while FEI typically amortizes accumulated deferral account balances and projected gas costs over the next twelve months when setting commodity rates, the rate setting guidelines also allow for discretion in consideration of spreading costs over the next twenty four months. This would be appropriate in the case when there is a significant difference in the forward gas costs for the next twelve months compared to the subsequent twelve months and where the deferral account balance may exceed the desired +/- $50 million threshold. In this case, amortizing the deferral balance over twelve months could result in more rate volatility than if the balance had been spread over twenty four months.

An example using the information from the April 1, 2014 commodity rate adjustment will help illustrate this point. When reviewing the forward gas costs and accumulated deferral balances in February 2014 to increase the commodity rate effective April 1, 2014, FEI looked at amortizing the costs over the next twenty four months, rather than just the next twelve months. This was because, while forward prices were higher that FEI's then current commodity rate out to March 2015, they were much lower for the April 2015 to March 2016 period. Setting the commodity rate based on the twenty four month cost outlook would lessen the required commodity rate increase effective April 1, 2014 and also reduce the risk of setting the rate too high and then having to reduce it as early as October 2014. It would also keep the projected deferral account balance within the +/- $50 million range during the twenty four month period. The following figures illustrate the commodity rate setting considerations.

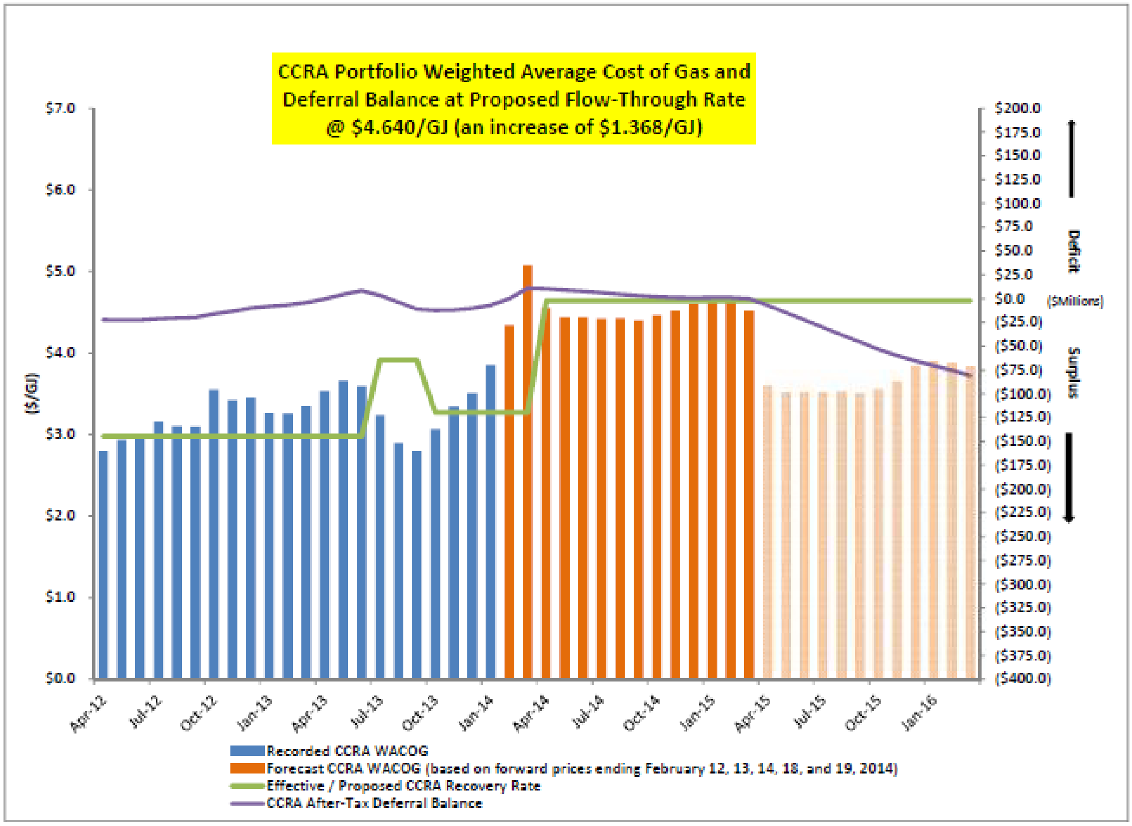
In Figure 5-2, FEI's residential commodity rate (Effective CCRA Recovery Rate) effective October 1, 2013 was $3.272/GJ. Market prices for the next twelve months averaged higher than FEI's commodity rate, due to the cold winter 2013/14 and low gas storage levels, resulting in higher projected gas costs (Forecast CCRA WACOG). Without a rate increase, FEI's deferral account balance was projected to climb to a deficit of over $100 million by March 2015 and to almost $150 million by March 2016, indicating that a rate increase was required.

Figure 5-2: FEI Forward Gas Costs and Deferral Balances with $3.272/GJ Commodity Rate



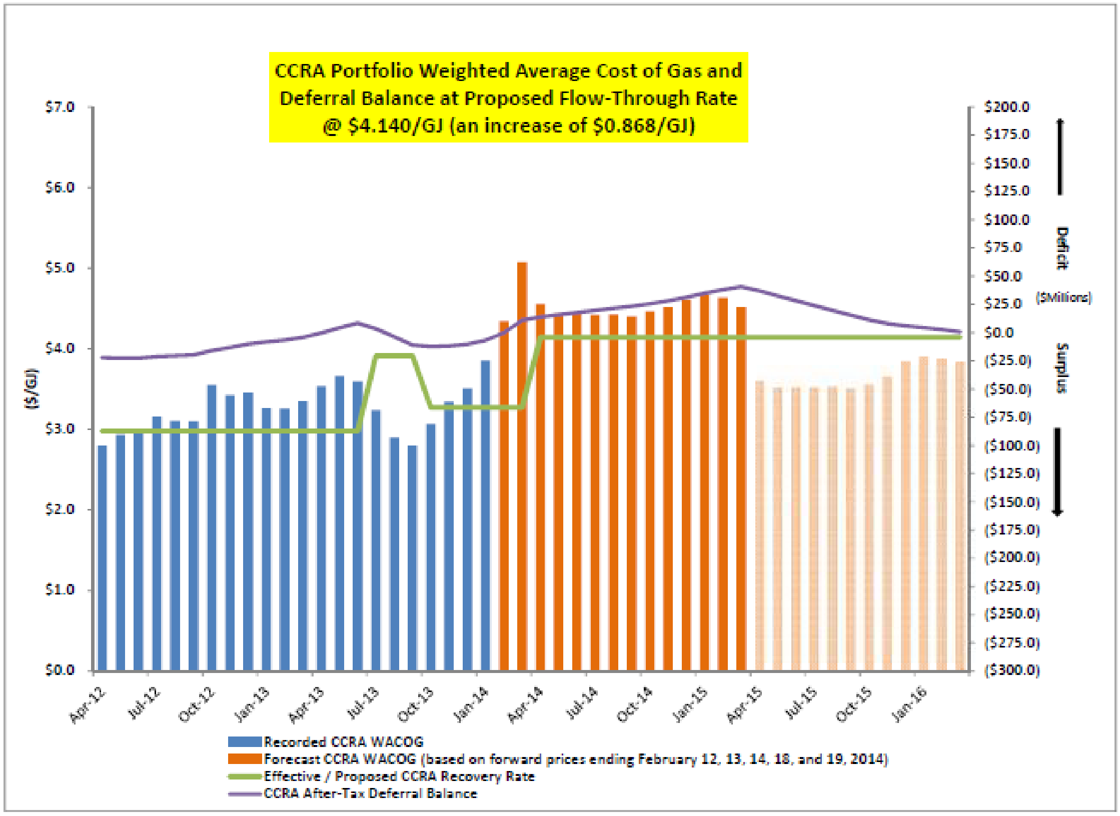
When looking at recovering the projected gas costs and the accumulated deferral balance over the next twelve months, the projected commodity costs indicated a rate increase to $4.64/GJ. In this case, because of the significant drop in forward gas costs after March 2015, the deferral account balance would increase to a surplus of almost $75 million by March 2016, triggering a rate decrease. This is illustrated in Figure 5-3 below.

Figure 5-3: FEI Forward Gas Costs and Deferral Balances with $4.64/GJ Commodity Rate



However, by amortizing projected gas costs and the deferral balance over twenty four months, the indicated commodity rate increase is reduced to $4.14/GJ and the potential for having to change rates again in twelve months is reduced. Furthermore, the forecast deferral account balance is projected to remain within the desired +/- $50 million range during the twenty four month period. This is illustrated in Figure 5-4.

Figure 5-4: FEI Forward Gas Costs and Deferral Balances with $4.14/GJ Commodity Rate



FEI believes that consideration of amortizing projected gas cost and deferral account balances over the twenty four month period is consistent with the rate setting guidelines. It could also help with mitigating future commodity rate volatility and managing deferral account balances within an acceptable range.

5.3 *FINANCIAL TOOLS AND STRATEGIES*

There are a number of financial hedging tools FEI can use to meet the price risk management objectives. These include locking in market prices through fixed price swaps or capping market prices with call options or collars. Each of these is effective in different market price environments as will be discussed in the following sections.

While some of these transactions can be done physically, where the buyer pays a fixed price or capped price for physical delivery by the seller, they have traditionally been done financially. In a financial transaction, the buyer swaps the index market price for a fixed or capped price with a counterparty, often a bank, and there is no physically exchange of gas supply. In a separate underlying transaction, FEI purchases physical supply from another counterparty, usually a gas producer, at the market index price.

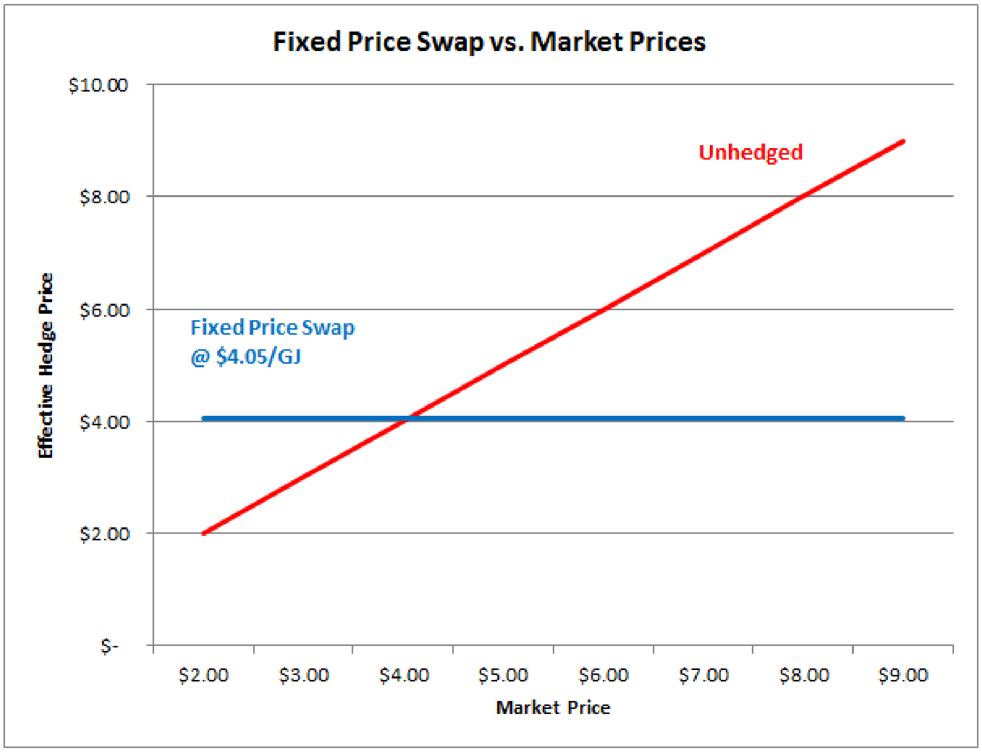
Hedging instruments involve locking in or capping market gas prices and so directly impact gas costs that customers will ultimately pay through commodity rates. As such, hedging can be used as a tool to stabilize market prices and protect customers from market price volatility and act like insurance against adverse price movements. Hedging strategies can be tailored to different market price environments so that they protect customers and provide some rate stability in a cost effective manner. Hedging also provides the opportunity to help preserve relatively low commodity rates for customers by capturing opportunities when they arise.

5.3.1 Fixed Price Swaps

Fixed price swaps are an effective way of locking in market prices to reduce the impacts of market price volatility on gas costs and rates. They can be transacted relatively quickly and so are effective in capturing favourable market price opportunities as they occur. Fixed price swaps can be used to capture market price opportunities if, for example, predefined price targets are reached, helping preserve favourable commodity rates and reducing price volatility for customers. It must be emphasized that this strategy is not about trying to 'beat the market' by capturing forward prices at levels below those where prices ultimately settle; it is about locking in favourable market prices to help preserve low commodity rates for customers. While the market price environment has recently been volatile, there may be opportunities to capture favourable prices for customers that would help preserve low commodity rates and provide some degree of protection market price fluctuations for the medium term. For example, one strategy could involve FEI locking in forward prices when they are below FEI's current commodity rate of $3.78/GJ. This would help improve the probability of lowering future commodity rates and capture market prices that compare favourably to FEI's five-year historical commodity rate average.

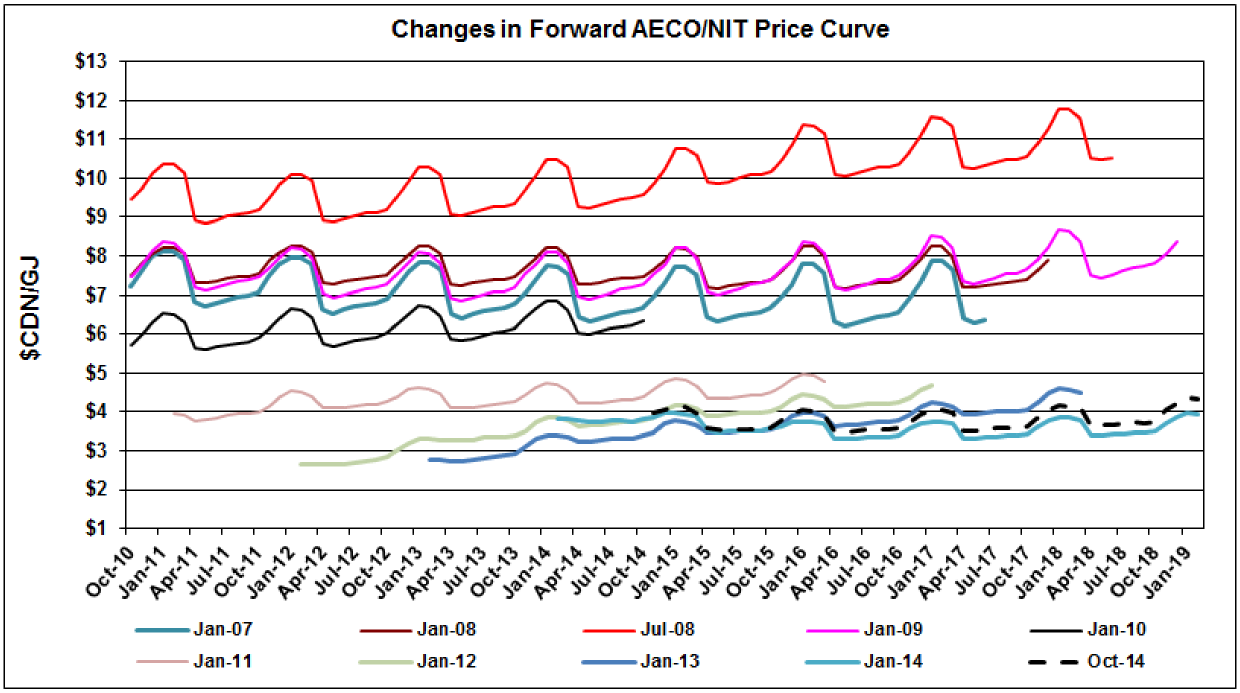
The following figure illustrates how fixed price swaps work under different market prices scenarios, assuming a forward market price of $4.05/GJ for AECO/NIT as of October 1, 2014.

Figure 5-5: Fixed Price Swaps under different market prices



The following figure shows how forward market prices have changed since January 2007. Recent forward market prices as of October 1, 2014 are favourable compared to price levels seen in previous years, trading near the lower end of the range since 2007. For example, as of October 1, 2014, there were opportunities to capture market prices at levels below the current FEI commodity rate of $3.78/GJ and the five-year average rate of $4.08/GJ.

Figure 5-6: Changes in AECO/NIT Forward Prices



By having a medium term hedging strategy in place, FEI will be able to take advantage of favourable market price conditions and capture price opportunities for customers when they arise.

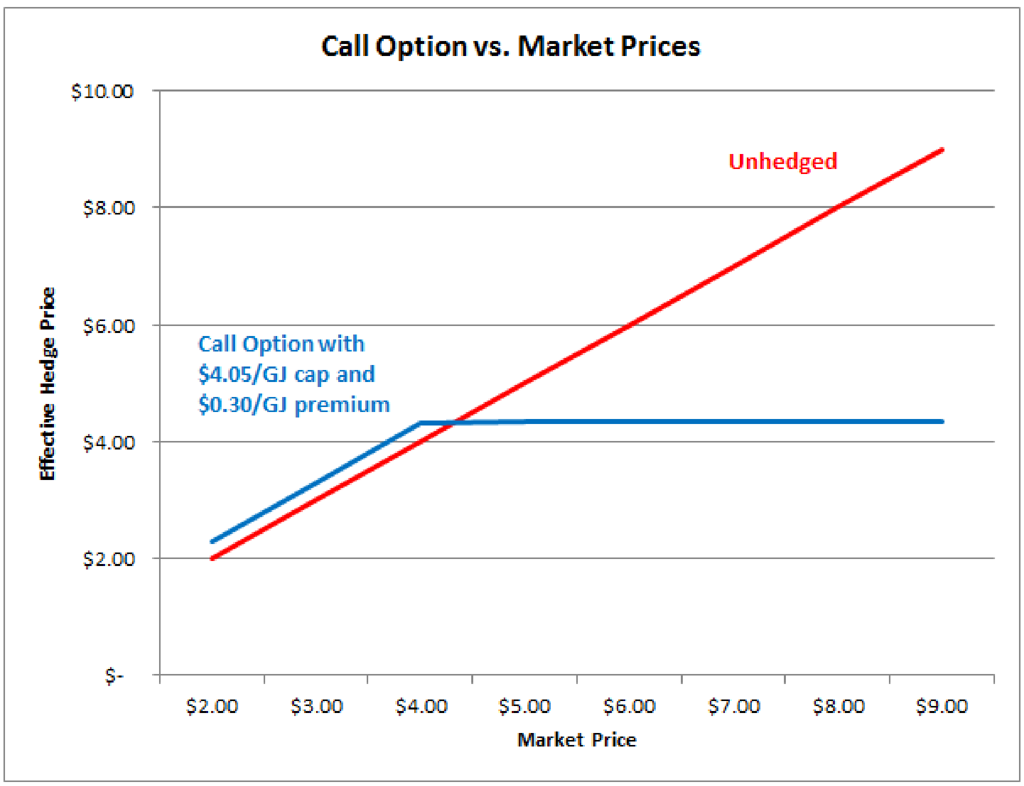
FEI recognizes and shares the Panel's concern raised in the Review decision with regard to potential hedging costs (i.e. out-of-market outcomes) for any fixed price hedging strategy. FEI agrees that the price risk management objectives should be achieved in a cost effective manner. In the Panel's review of the hedging strategy, it noted that recent years' hedging costs had been significant, as hedges layered in prior to the significant market price declines in 2009 and 2010 ended up being above actual market prices. This is because the natural gas supply and demand balance was tighter prior to 2009 and forward prices for natural gas were trading at levels near $6/GJ and $7/GJ and even higher at times. In fact, natural gas imports into North America were being considered at that time to help meet demand as domestic supply was declining.

However, in the current market price environment, characterized by a healthier gas supply outlook, forward market prices are at lower levels and closer to gas production costs for many dry gas plays (see Section 2.5 of Appendix A). For this reason, FEI believes that any potential market price decreases are not likely to be of the same magnitude as when market prices were trading at the $6/GJ to $7/GJ levels. As such, the likelihood and amount of potential hedging costs is significantly reduced when compared to previous years. However, with any hedging strategy or program, there is always the potential for hedging costs (as well as gains). The key to a successful program is its ability to meet the objectives without incurring significant hedging costs. Therefore, FEI recommends implementing fixed price swaps only in relatively low market price environments in the interests of preserving relatively low commodity rates for customers. Other hedging instruments, such as call options or costless collars, which provide downside price participation, could also be used in higher priced environments.

5.3.2 Call Options

One way of reducing rate volatility and protecting customers from rising prices while mitigating potential hedging costs would be to use call options instead of fixed price swaps. These instruments could be used in higher market price environments, where there is the potential for prices to move significantly lower or higher in the future. With these instruments, a premium is paid by the buyer to receive a capped price. The capped price would provide price protection if market prices moved higher. If market prices remained below the capped price, then the option would provide downside price participation. The following figure illustrates how call options work under different market prices scenarios.

Figure 5-7: Call Option under different market prices



Based on recent indications for winter 2014/15, premiums are about $0.30/GJ for a call option with a cap price equal to current forward market prices of about $4.05/GJ[43].

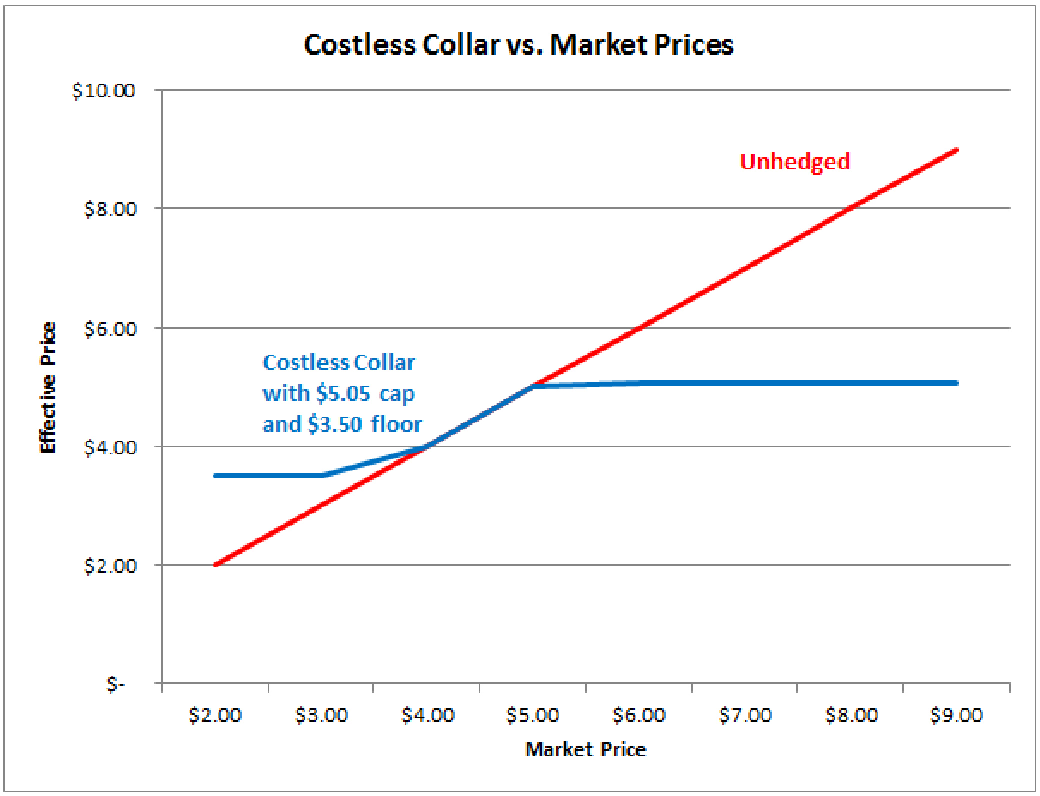
Because these instruments provide downside market price participation, they would not typically be used in relatively low market price environments where the price downside is limited.

[43] Based on October 1, 2014 forward market prices.

5.3.3 Costless Collars

Another hedging alternative to mitigating market price volatility is the use of costless collars. Costless collars are hedging instruments involving the use of a cap and a floor price. The costless collar ensures that the purchaser of the instrument will not pay more than the capped price if market prices move above this level. It also ensures that the purchaser will pay the floor price if market prices move below this level. The following figure illustrates the resulting hedge price under different market price scenarios using costless collars.

Figure 5-8: Costless Collar under different market prices



The main advantage of this instrument is that the purchaser can limit market price exposure to a predefined range. Therefore, costless collars make sense to use in a market price environments where there is potential for significant upside and downside market price movement. They make less sense to use in a low market price environment when there is limited price downside; in this case, using fixed price instruments makes more sense.

Costless collars can result in lower potential hedging costs than fixed price swaps if market prices move lower. While there is no explicit premium with costless collars, as there is with call options, the premium is implicit in the limited downside price potential. The higher the capped ceiling price requested by the purchaser, the lower the possible floor price. For example, a costless collar for winter 2014/15 with a $5.05/GJ ceiling price would yield a $3.50/GJ floor price. And a costless collar for the same winter with a $6.05/GJ ceiling price would yield a $3.20/GJ floor price. This is based on the forward market price for winter 2014/15 of

$4.05/GJ[44]. Costless collars, like call options, are available for the AECO/NIT market but not typically available for the Station 2 or Sumas markets because of the lower levels of liquidity in those markets.

Similar to using fixed price swaps to capture market price opportunities, the use of call options or costless collars is not expected to mitigate longer term and persistent periods of market price volatility. However, they would help with stability in commodity rates for FEI in the medium term.

These instruments should be included as part of a medium term (i.e. up to three years out) hedging program, as recommended by FEI, Aether and RiskCentrix. This recommendation is discussed further in Sections 8 and 9.

The following section discusses price risk management alternatives used in other jurisdictions for information and comparative purposes.

[44] Based on forward market prices and costless collar price indications as of October 1, 2014.

6. PRICE RISK MANAGEMENT IN OTHER JURISDICTIONS

Utilities in other jurisdictions in North America use a variety of tools and mechanisms for price risk management. Most utilities use both short term strategies, such as using natural gas storage, and employ a medium term hedging program while some use longer term tools such as investing in reserves.

6.1 *HEDGING*

6.1.1 U.S. Utilities

Hedging is an important component of price risk management for many utilities in North America. As Aether describes in Part IX – How Other Utilities Look at Price Risk Management of its review report, recent surveys by the American Gas Association (AGA) and National Regulatory Research Institute (NRRI) indicate that most U.S. utilities utilize financial hedging instruments along with natural gas storage to protect customers from medium-term market price volatility[45]. Many utilities use a variety of hedging instruments and terms, depending on market price conditions and their price risk policies. Those utilities that do short term hedging (i.e. up to one year) hedge between 50 percent and 80 percent of their base volume requirements and use fixed price swaps or call options. Those utilities that hedge out three years will typically hedge more in the first year and declining amounts for years two and three. They will often hedge some minimum volume and then hedge the remaining volume based upon certain price targets being met or portfolio risk exposure.

6.1.1.1 PNW Utilities

Major gas and electric utilities in the PNW region actively use natural gas storage and hedging as part of their medium-term price risk management. These utilities operate in the same regional marketplace as FEI and include Cascade Natural Gas, Intermountain Gas, Puget Sound Energy (Puget), Avista Utilities (Avista), NWN and Portland General Electric. These utilities use financial hedges and/or fixed price purchases and/or options to manage gas or electricity rate volatility for up to several years out for customers. While many of them use a programmatic approach to hedging, some, such as Avista for example, also use hedging to capture market opportunities as they arise, with targets based on forward market prices. Puget uses probability modelling when hedging to determine the hedging strategy's potential effects on the portfolio. Appendix C of Aether's review report provides more information regarding other utilities medium-term price risk management.

In January 2014, a workshop was held with Washington state gas utilities, stakeholders and the Washington Utilities and Transportation Commission (WUTC) to discuss natural gas hedging policy issues and current reporting practices, seeking input from a variety of stakeholders[46].

[45] Aether Review report, page 75.
[46] Per Washington Utilities and Transportation Commission Docket UG-132019.

Experts on risk management also presented at the workshop, with RiskCentrix promoting the development of more robust hedging plans[47]. Ken Costello of The National Regulatory Research Institute (NRRI) stated that, while regulators should set hedging guidelines for utilities, they should not determine the details of the hedging plans or engage in hindsight review[48]. While there were no directives yet to come from the workshop for the state utilities and they continue to use hedges, the WUTC is looking into whether requirements for reporting are appropriate or a policy statement about reporting, best practices or any other topics would be in the interest of all parties.

6.1.2 Canadian Utilities

Hedging by the major Canadian gas utilities is not as accepted by regulators as it is in the U.S. All of the major Canadian utilities use natural gas storage as part of their price risk management given the peaky nature of winter demand in Canada.

The primary natural gas utilities in Ontario had hedging programs in the past but currently do not. Union Gas Limited (Union Gas) and Enbridge Gas Distribution Inc. (Enbridge) effectively had their hedging programs cancelled in 2008 and 2007, respectively, following a review by the Ontario Energy Board (OEB). While these utilities maintained that their risk management activities had provided a material reduction in rate volatility for customers at a minimal cost, the OEB disagreed and argued that the quarterly rate adjustment mechanism process and the equal billing plan provided sufficient rate smoothing effects. Union Gas and Enbridge disagreed with this assertion and argued that the quarterly rate adjustment mechanism process and the equal billing plan do not provide the same degree of rate volatility mitigation as an effective hedging program.

In more recent news, the OEB announced that it would be reducing the impact of the latest commodity rate increase for Enbridge natural gas customers. Given the cold winter of 2013/14 and increases in market gas prices, Enbridge had proposed a 40 percent increase in natural gas rates for customers effective April 1, 2014 based on recovering gas costs over the next twelve months. However, in order to lessen the immediate blow to customers, the OEB directed Enbridge to recover gas costs over a longer period of twenty seven months, thereby reducing the recent commodity rate increase.

Centra Gas Manitoba Inc. (Centra Manitoba) is another utility that manages rate volatility for customers. Centra Manitoba does this primarily through fixed rate offerings for customers instead of through its default standard commodity rate offering. In 2009, Centra Manitoba was directed by the Manitoba Public Utilities Board to provide fixed price offerings to residential and commercial customers for one, three and five year terms and wind down its hedging program related to its quarterly standard variable rate offering. Therefore, those customers that desire stability in rates can choose to purchase their commodity supply from Centra Manitoba or gas

[47] Encouraging "Robust" Risk Mitigation presentation by Mike Gettings, RiskCentrix, January 23, 2014.
[48] "Teeing Off" the Discussion on Gas Hedging presentation by Ken Costello, Principal Researcher, National Regulatory Research Institute, January 23, 2014.

marketers. At this point, Centra Manitoba's share of fixed rate contracts is minimal, equalling less than 0.5 percent of total customer sales volumes. The share for natural gas marketers is about 10 percent.

SaskEnergy Incorporated (SaskEnergy) continues to use hedging to manage rate volatility for customers. SaskEnergy hedges for up to five years out and up to 90 percent of its winter supply purchase volumes in the first year, with lower percentages hedged for subsequent years. The utility uses a mix of financial fixed price swaps and options and physical fixed price purchases. The hedging strategy includes a programmatic approach with some discretion to increase hedging if favourable market prices are available. This hedging program has enabled SaskEnergy to change commodity rates less frequently than some other utilities, despite the price volatility in the marketplace. In fact, SaskEnergy's last commodity rate change was in April 2012 when it reduced the commodity rate to $3.82/GJ. However, because of the higher market prices during the past winter 2013/14 and increasing deferral account deficit, the company received approval for its first commodity rate increase in six years to $4.84/GJ effective July 1, 2014. In 2013, SaskEnergy conducted some customer research to gauge residential and commercial customers' interest in rate stability versus market price exposure. The results showed that most customers preferred the rate stability provided by the utility in order to manage household or business budgeting.

Gaz Métro Limited Partnership (Gaz Métro) in Quebec has recently undergone a review of its hedging program. The review report is provided in Appendix H. The regulator, the Régie de l'Energie (the Régie), suspended application of the hedging program in its November 2012 decision and asked Gaz Métro to present a proposal aimed at maintaining, reformulating, or suspending the hedging program based on the recommendations of an outside consultant during the latest 2014 rate application. As part of this review, Gaz Métro conducted customer surveys to determine customers' views on rate volatility. The results show that residential and commercial customers, in general, desire rate stability and did not want the hedging program to be terminated.

Gaz used the services of a consultant, Concentric, to help with the review of its hedging program. Appendix I provides more details regarding Concentric's Assessment of Gaz Métro's Financial Derivatives Program dated September 26, 2013. Within this appendix, Ruben Moreno, Concentric's Vice-President, recommends that Gaz Métro's hedging program not be discontinued but rather enhanced to improve its performance in meeting the objectives of reducing rate volatility, maintaining competitiveness and avoiding excessive downside risk exposure. Moreno suggests the following enhancements:

- Use more formal measures of risk reduction, such as Value at Risk (VaR)[49], to monitor, control and evaluate hedging;

[49] Value at risk, or VaR, is a means of measuring the amount of financial risk present in a specific commodity and was originally developed to address the risk of stocks, foreign exchange and interest rates. There are two main components used to determine the value at risk. First, the time period to be considered is established. This may be a day, a month, or even a year. Next, the overall confidence level of the predictions must be ascertained; this

- Understand customer risk tolerances, such as through regular customer surveys, to determine hedging protocols;
- Programmatic hedging should be limited and more defensive hedging should be used; and
- Defensive hedging is defined by risk tolerances and it only occurs if there is a high probability of breaching tolerances. This monitor-and-respond approach helps to limit potential hedging costs as small hedging adjustments are made over time.

This assessment is consistent with the recommendations provided by Aether and RiskCentix and by those provided by FEI within this report.

Despite the evidence in favour of an enhanced hedging program and support from interveners, including consumer groups and municipalities, the Régie ordered Gaz Métro to end its hedging program in May 2014.

6.2 LONGER TERM PRICE RISK MANAGEMENT

Some U.S. utilities also engage or plan to engage in longer term price risk management activities, such as NWN, Northwestern Energy (Northwestern), PacifiCorp, Portland General Electric (PGE) and Florida Power and Light Company (FPL).

As discussed in Section 5.1.4, NWN includes investment in reserves as part of its overall price risk management strategy. In its latest 2014 IRP, NWN states that its multi-year action plan includes increasing its long-term hedged position of gas requirements from the current level of approximately 10 percent up to 25 percent.[50] NWN believes that the current low market price environment (relative to historical prices) is not expected to last as the demand for natural gas increases over time and so increasing cost-based supply will help meet its objectives. NWN states: “While there can never be any guarantees, this appears to be a prime time for locking in long-term gas prices for a larger portion of the portfolio. Whether or not this results in a portfolio that beats the market will not be known for many years and is not the point in any case, because now is the time to increase the Company’s “insurance policy” against the price volatility that the above factors can be reasonably expected to create in the market.”[51]

Northwestern has acquired gas production in major plays in Montana in order to mitigate supply cost and rate volatility for its customers. Northwestern plans to increase its reserves holdings and recently completed an acquisition in the Bear Paw Basin from Devon Energy Production Company, L.P. Northwestern recently announced: “We’re pleased to have secured another gas production asset in Montana that will help provide long-term supply price stability and reliability

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typically requires market research and analysis of historic performance data. Typically confidence levels are set at either 95% or 99% probability. Value at risk calculations are intended to provide an overview of likely risk scenarios for hedging portfolios. (Source: Concentric’s Assessment of Gas Metro’s Financial Derivatives Program, September 26, 2013).

[50] NWN 2014 Integrated Resource Plan, page 1.21.

[51] NWN 2014 Integrated Resource Plan, page 3.40.

for our customers".[52] The purchase is expected to result in a twenty-year levelized average price for customers of approximately $4.10/Dth (the equivalent of about $4.27/GJ). This increases the company's total gas reserves to 37 percent of its gas supply portfolio.[53]

PacifiCorp has indicated its plans within its 2013 IRP to solicit bids to secure long term natural gas hedging products (up to ten years) in order to reduce power cost variability for customers. PacifiCorp states the role of this hedging in the IRP: "The purpose of hedging is not to reduce or minimize net power costs. The Company cannot predict the direction or sustainability of changes in forward prices. Therefore, the Company hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the Company's risk management policy."[54]

PGE has also expressed its intent to further investigate longer term price risk management strategies such as investing in reserves. Their 2013 IRP states: "To improve longer-term price and supply stability, we are also exploring opportunities for gas-in-the-ground reserves, but have not executed any such transactions. Such contracts are priced at a premium and require collateral. However, given the historically low gas prices, our Action Plan calls for further exploration of the potential merits of long-term gas supply (including storage and reserves)."[55]

FPL is investigating investing in natural gas reserves in order to provide more stable fuel supply for its gas-fired power plants that serve electricity customers. FPL is partnering with PetroQuest Energy Inc., an independent oil and natural gas producer, in a joint venture to develop natural gas wells in the Woodford shale region in south eastern Oklahoma. The CEO of FPL recently stated: "We believe this to be the next logical step in providing clean electricity for our customers at affordable prices. This investment in natural gas production is an important component for delivering lower, more stable natural gas prices for our customers, and we anticipate identifying additional investment opportunities, thereby benefiting our customers even more over the long term."[56] A FPL spokesperson added: "FPL would be able to lock in gas prices at production costs rather than relying on market prices. The gas reserves would provide additional price stabilization to FPL's existing financial hedging program in two respects. The existing program focuses on short-term transactions because of the cost and credit risks associated with long-term financial hedges, whereas the gas reserves would provide a hedge against market-price volatility over multiple decades."[57]

Aether provides examples of other utilities' long term price risk management initiatives in Appendix C of its report.

52 http://www.northwesternenergy.com/news/2013/12/02/NorthWestern-Energy-Completes-Purchase-of-Natural-Gas-Assets-in-Montana
53 http://www.marketwatch.com/story/northwestern-energy-announces-agreement-to-purchase-natural-gas-assets-in-montana-2013-05-28
54 PacifiCorp 2013 IRP, April 30, 2013, page 274.
55 http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf, page 98.
56 http://www.naturalgasintel.com/articles/98823-florida-electric-utility-going-to-wellhead-for-better-gas-deal
57 http://www.naturalgasintel.com/articles/98823-florida-electric-utility-going-to-wellhead-for-better-gas-deal

7. CUSTOMER RESEARCH AND ALTERNATIVE OPTIONAL RATE OFFERINGS

In the Panel's recommendations in the Review decision, FEI was encouraged to assess customers' views regarding their preferences for alternative commodity rate offerings. The Panel emphasized the importance of choice for customers but also indicated that any costs related to such offerings should be borne by those customers that find value in them. This section provides an assessment of these alternatives that could be made available to customers. These alternatives include a hedged commodity rate as well as the Price Stability Fund (PSF) approach proposed by CEC. The recently conducted customer research provides greater insight into customers' preferences regarding these possible alternative rate offerings and structures.

7.1 *CUSTOMER RESEARCH*

In order to assess customers' tolerances for rate and bill fluctuations and possible preferences for alternative rate offerings and structures, FEI conducted quantitative research and qualitative research with focus groups. Companies with extensive experience in market research were selected by FEI, with Sentis Market Research Inc. (Sentis) conducting the survey and Participant Research (Participant) leading the focus groups. The research approach and survey questions were reviewed with Commission staff prior to their implementation. The detailed results of the survey, conducted in June and July 2012, are provided in Appendix C. The focus groups were conducted in September 2012 and the results are provided in Appendix D. Sentis and Participant presented the research results to FEI and Commission staff as well as members from CEC and BCOAPO on October 22, 2012. This presentation is included in Appendix E.

At a high level, the research indicates that customers continue to be concerned about gas price and rate volatility and rising natural gas prices in the future. Customers, in general, also have a low understanding of their natural gas bill and its components. While the research results show that more customers prefer the current FEI market-based commodity rate, adjusted on a quarterly basis, there is also significant interest in other alternative offerings. Customers also indicated that interest in alternatives that provide more rate stability would increase if market prices and volatility increased.

In conducting the research, customers were presented with four alternative rate offerings:

- Market rate – This is essentially the current FEI commodity rate offering but excluding any further price risk management such as hedging.
- Hedged rate (Price Protect) – This alternative would be a hedged commodity rate, with either half or all of customers' volumes locked in at a fixed rate. The rate could be locked in for periods of six months up to three years.
- Capped rate (Rate Cap) – This alternative would include a market-based rate with a cap, or ceiling. Customers would not pay above the cap, regardless of how high market gas

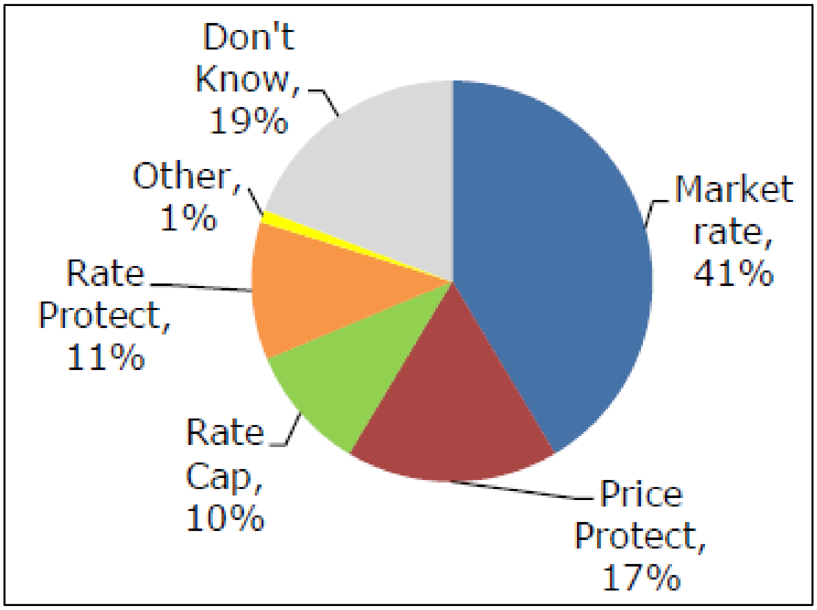
prices go. Customers would benefit from declining rates if market prices fell below the cap.

- Price Stability Fund (Rate Protect) – This alternative would require that customers pay a premium on the FEI commodity rate which would be accumulated in a fund. This fund would then be used to offset higher market prices and rates if they occurred in the future.

Research was also conducted regarding customers' views of the Equal Payment Plan because it is one of the ways customers can reduce bill fluctuations due to consumption profile.

The results of the survey regarding these alternatives are presented in the following figure.

Figure 7-1: Residential Customer Alternatives Preferences[58]



Each of these alternatives will now be discussed in more detail.

7.1.1 Market Rate

When choosing between the four options, the market-based rate offering, the hedged rate, the capped rate and the PSF, the survey showed that customers selected the market-based rate offering more frequently than the other options (41 percent each for residential and commercial customers).

With regard to the adjustment period, the majority of customers preferred a quarterly adjustment period when given the option of a longer adjustment period, such as semi-annual or annual. This aligns with FEI's current practice of reviewing the commodity rate on a quarterly basis. During the focus groups, respondents said that they would have more interest in the other alternatives if gas prices were increasing beyond a normal rate (e.g. inflation).

[58] Sentis Alternatives for Managing Natural Gas Price Volatility survey results report, August 20, 2012, page 35.

7.1.2 Hedged Rate

A hedged commodity rate would appeal to those customers who want a greater degree of market price volatility protection than is currently offered by the FEI market-based commodity rate offering (which includes no hedging protection given the expiry of all FEI hedges at the end of March 2014). It could include different degrees of volatility reduction, such as 50 percent or 100 percent of consumption volume hedged, depending on customer preferences. A 50 percent hedged offering would provide similar volatility protection as the FEI commodity rate structure prior to the denial of its enhanced hedging strategy per the 2011-2014 PRMP. A 100 percent hedged offering would be similar to the fixed rate products offered by natural gas marketers under the Customer Choice program. Terms of six months up to three years could be provided to customers.

The survey shows that the hedged rate appealed to a significant number of customers; about 17 percent of residential and 18 percent of commercial customers. Most residential customers prefer to have half, rather than all, of their consumption locked in at a fixed price while commercial customers were closer to being evenly split. This is a reflection that many customers do not like being locked in with a fixed rate but do prefer some degree of market price protection. A one year term was the most popular term selected by both residential and commercial customers regarding the hedged rate. When given a choice between selecting a fixed rate offered by FEI versus a natural gas marketer, customers favoured FEI.

The qualitative research revealed that some customers had concerns with this alternative. In particular, customers were concerned about being locked in at a rate higher than the market (if market prices fell) and this rate was seen as similar to the gas marketers' offerings, which were not viewed favourably. Customers believed this alternative makes more sense when market prices and rates are more volatile.

7.1.3 Capped Rate

The survey results show that 10 percent of residential and commercial customers would select the capped rate product. This option might appeal to customers who prefer some degree of commodity rate stability but do not prefer to be locked in at a fixed price or who are wary of marketers' fixed rate offerings. The focus groups revealed that this alternative was more appealing than the hedged rate or PSF options. Customers liked the fact that this offering would provide lower rates if market prices decreased and that they would not be locked in at a higher rate than the market.

7.1.4 Price Stability Fund

The Price Stability Fund was suggested by CEC as an option for customers during the review of the FEI hedging strategy in 2011. CEC suggested that while some customers might prefer this PSF, others may elect for a hedged commodity rate and some may not want either form of rate or price protection. CEC's proposal for the PSF would involve charging customers a premium above the FEI standard market-based commodity rate and capturing the difference in a fund which would be refunded back to customers during periods when commodity rates are higher. As an example, FEI could forecast its natural gas costs for the next two years and then charge this to customers, on a per unit basis, plus an added premium. Based on recent market prices, this would yield a commodity charge in the order of $3.75/GJ. If a premium of $0.50/GJ were charged, these customers would pay $4.25/GJ for the next two years, unless market prices changed significantly from forecast. If market prices did move above this $4.25/GJ level for an extended period of time, FEI could refund the accumulated PSF back to customers so that their commodity rate would remain at $3.75/GJ.

The survey results show that this alternative appealed overall to less customers than the market, hedged or capped rate, being selected by 11 percent of residential and 6 percent of commercial customers. It was also not regarded favourably within the focus groups. Participants found it complicated and expressed concerns with how the fund would be monitored and refunded back, especially if customers moved.

FEI also has a number of concerns with this option. Depending on the timing of offerings to customers, FEI would have to track the accumulated PSF contributions from individual or groups of customers so that the balances could be refunded back to those specific customers or groups if market prices moved higher. Furthermore, there is the question of how much premium to charge customers and, if market prices move higher, how much should be refunded back given that market prices could move higher, or back down again, in the future.

7.1.5 "Don't Know" Responses

The survey results indicated that a significant portion, about 19 percent, of residential customers did not know which of the alternative rate offerings appealed to them. This highlights the fact that many customers do not have a good understanding of their natural gas bills and that too many alternatives to consider without deeper knowledge of how they work may be confusing. This presents a significant challenge for FEI in terms of providing new commodity rate offerings. Gaz Metro also discussed its experiences in this regard in the review of its hedging program: "…The [Hedging] Program is an abstract and complex concept and Gaz Métro believes the majority of its supply service customers do not have the required knowledge to easily understand and assimilate the impacts of the choice that would be offered to them and thus to make an informed decision."[59]

7.1.6 Equal Payment Plan

Within the survey and focus groups, customers were asked about their awareness and appeal of the EPP and if the adjustment period should be changed. Most participants were aware of the EPP and residential customers were much more likely than commercial customers to sign up for the EPP. Reasons for signing up for the EPP included the preference for having consistent bills throughout the year and smoothing out higher winter bills for easier budgeting. When asked about the EPP adjustment period, most participants selected the quarterly

[59] Gaz Metro Proposals for a Financial Derivatives Program, page 32, provided in Appendix H.

adjustment period rather than the longer adjustment period options, such as annually, even though many participants were unaware that the EPP is already adjusted quarterly. Participants would prefer smaller, more frequent, adjustments rather than fewer, potentially larger, adjustments for household budgeting purposes.

7.1.7 Previous Customer Research

Prior to this recent customer research conducted in 2012, FEI had also conducted some customer research in 2005. In February 2005, FEI engaged a research company to survey customers regarding their tolerance for rate volatility. The results of the Residential Customer Price Volatility Preferences Study, conducted in February 2005 by Western Opinion Research Inc. and submitted in the 2005-2008 Price Risk Management Plan, indicated that customers prefer rate stability. The study has been included in Appendix F of this report. The survey results confirmed that customers will tolerate some volatility in rates but that there were limits largely based on household budget constraints. The study revealed the following insights and preferences among residential customers:

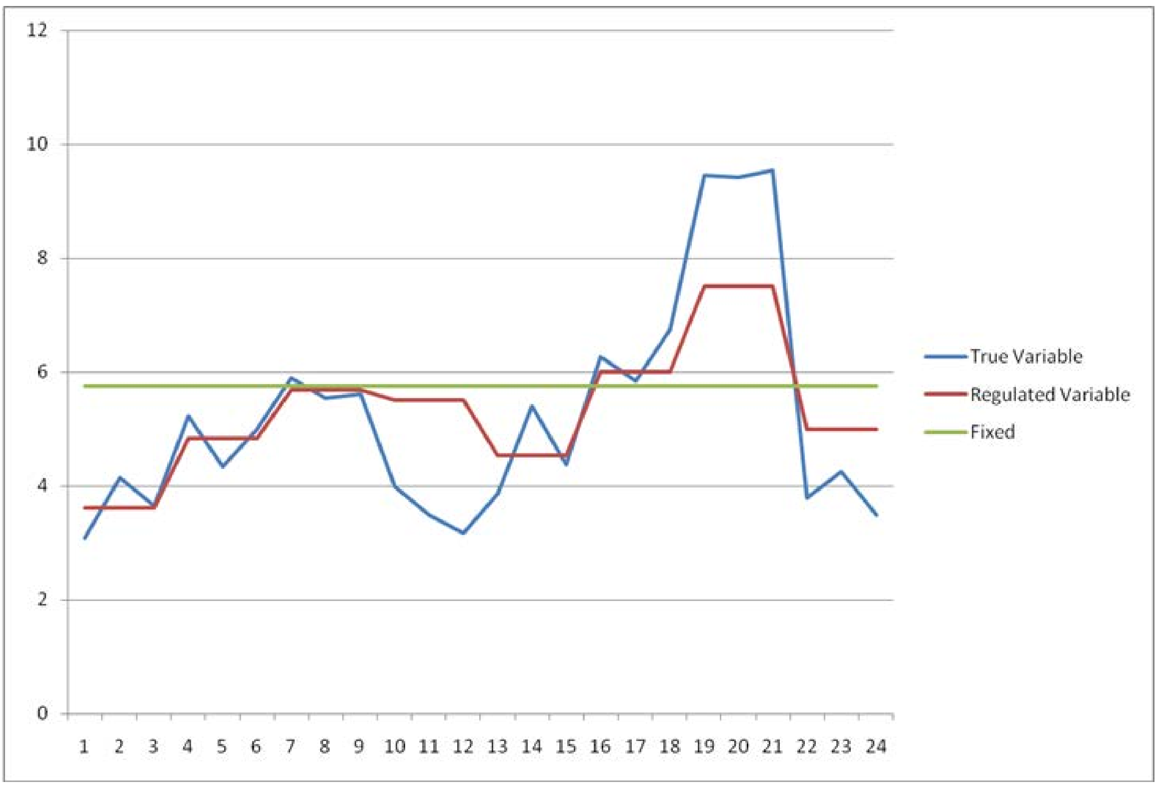
- Natural gas bills are considered among the more significant monthly payments;
- Many customers cannot afford large increases in their natural gas bills;
- On average, the study respondents can tolerate annual natural gas billing changes of $169 (or 16 percent of average annual billing of $1033);
- For those respondents on tighter budgets with annual billings of less than $900, the average tolerable change was only $53 (or 11 percent of average annual billings of $482);
- For those respondents with higher budgets with annual billings of more than $900, the average tolerable change was $219 (or 17 percent of average annual billings of $1288); and
- 70 percent of respondents could tolerate annual bill changes of $100 or less.

This last point illustrates that most participants could not tolerate annual bill changes of more than $100. Based on FEI's current average total residential annual billing of about $1,000 (assuming 95 GJ consumed per year and a burner tip rate of $10.20/GJ based on FEI's commodity, midstream and delivery rates and fixed basic charge rate effective October 1, 2014 and excluding carbon tax) this tolerable increase represents approximately 10 percent or $1/GJ. FEI's last commodity rate increase effective April 1, 2014 was about $1.37/GJ.

In the study, customers were also queried about their preferences for natural gas price hedging. The example of fixed versus variable rate mortgages was used to illustrate how hedging works. Participants were presented with three scenarios including a fixed rate bill scenario, a scenario where bills fluctuated with market prices (based on no hedging) and a scenario where bill changes were dampened from market price movements with some hedging. The majority of respondents chose the latter and were willing to accept less downside rate participation if upside rate increases were also limited. This is because many participants do not like or could not afford large bill increases and greater rate volatility made budgeting more difficult.

In November 2010, FEI enlisted Ideba, a research and consulting company, to conduct a focus group regarding residential customer preferences about “evergreening”, or automatic contract renewal, for customers enrolled with marketers under the Customer Choice Program. During this session, customers were also queried about their preferences for rate stability. Participants were presented with three rate scenarios including a fixed rate, a true variable (or market) rate and a controlled, or regulated variable, rate (one limited within a tighter range than the variable rate). The scenarios were not representative of historical natural gas prices or rates but were illustrative examples of rates to assess consumers’ preferences. The scenarios are shown in the following graph (with unit rates on the vertical axis and time on the horizontal axis).

Figure 7-2: Illustrative Rate Scenarios



One participant preferred the fixed rate because he was on a fixed budget. However, he noted that this fixed rate must be reasonable or close to the average variable rate over the long run to be of any value. One participant preferred the variable rate based on her belief that rate increases would be matched with rate decreases. This participant did not have any concerns with significant fluctuations in monthly bills or budget constraints. However, the majority of respondents favoured a controlled rate and were willing to accept less downside rate participation than the variable rate if upside rate increases were also limited. The desire for some rate stability and less bill surprises (i.e. significant bill increases from one month to the next) were cited as reasons for selecting this controlled rate.

The results of this focus group help validate the findings of the Residential Customer Price Volatility Preferences Study conducted in 2005 and indicate that customers' preferences have not changed materially over time. Many customers prefer some degree of protection from market price volatility given that they have limited budgets for bills. These customers are willing to accept smaller rate decreases if rate increases are also limited.

7.2 CONCLUSIONS REGARDING OPTIONAL RATE OFFERINGS

The customer research indicates that many customers prefer some rate stability in order to manage household or business budgeting and significant rate or bill surprises make this difficult. However, most customers also do not want to be locked into a fixed rate, with no potential downward rate movement opportunities. Customers are willing to accept smaller rate decreases if large rate increases can be avoided. The research also indicates that customers generally prefer fewer options and have a low understanding of their natural gas bill[60], which would make the offering of new fixed or capped rate products challenging for FEI. FEI refers to the Manitoba Hydro example, where the utility was directed to provide fixed rate offerings to customers in order to provide greater competition for natural gas marketers. The uptake of the utility fixed rate offerings has been very minimal to date, amounting to less than 0.5 percent of the total. Also, many FEI customers are wary of the fixed rate offerings provided by natural gas marketers under the Customer Choice program. Furthermore, there could be significant requirements and costs relating to customer education, administration and systems. Therefore, FEI recommends more comprehensive price risk management on a portfolio basis for its commodity rate customers rather than tailoring specific price risk management strategies to optional commodity rate offerings. Furthermore, providing an alternative fixed or capped rate product may appeal to only a small segment of customers and would leave the majority of FEI's customers exposed to market price volatility.

Therefore, as part of its recommendations, FEI recommends implementing a medium term hedging program to mitigate market price volatility and enable FEI to capture favourable market price opportunities if they arise. FEI believes that conducting further customer research regarding customers' tolerable annual bill increases would help determine more definitive hedging parameters, such as amounts to hedge and instruments, depending upon market price conditions and volatility. This is consistent with RiskCentrix's recommendations as part of its defensive hedging strategy. It is also consistent with Aether's recommendations, which are presented in the following section.

[60] Sentis Alternatives for Managing Natural Gas Price Volatility – Focus Group Report, October 24, 2012, page 15 provided in Appendix D.

8. AETHER RECOMMENDATIONS

As discussed in Section 2, FEI enlisted the services of Aether to provide an independent assessment of FEI's price risk management in light of the market environment, tools and instruments available to FEI and customer preferences. This section provides a summary of Aether's recommendations. The details are provided in Part X – Conclusions and Recommendations of Aether's report in Appendix G.

Aether recommends more comprehensive price risk management for FEI in mitigating market price volatility for its customers. This is based on Aether's assessment of the natural gas marketplace and the risks this poses for customers in terms of potential rate increases and volatility, the strategies and tools used by other utilities, the Panel Review directives as well as FEI's price risk management objectives and customer research. Aether suggests the following price risk management initiatives for FEI:

- Understand customers' preferences;
- Develop a customer rate tolerance;
- Re-institute a medium-term price risk management program design;
- Conduct scenario analysis, and
- Consider long-term price risk management options.

Aether recommends that FEI continue with its research regarding customers' preferences and tolerances regarding rate and bill changes. This will enable more definitive targets in terms of managing price risk for customers. It will also enable FEI to better understand how customers' tolerances may change in different market price environments.

Aether also recommends re-instituting a medium-term (i.e. up to three years) price risk management program design. Aether notes that while the use of deferral accounts and the quarterly rate setting mechanism and EPP provides some rate and bill smoothing effects, these do not protect customers from rising gas prices. Therefore, a hedging program is recommended for a portion of the portfolio, based on customers' risk tolerances and preferences. The program should be flexible and use different instruments in different market price environments, keeping in mind the objective related to cost effectiveness.

Conducting scenario analysis will help in determining the impacts of various market price scenarios on FEI's gas portfolio as well as the potential impacts of different hedging strategies. This will help determine the ability of the strategies to meet the objectives. Aether suggests FEI consider the VaR methodology to help measure potential price risk in the FEI gas portfolio. This approach uses historical or forward implied market price volatility to provide a range of potential portfolio outcomes. RiskCentrix also recommended this as part of a monitor and respond approach to hedging, rather than a purely programmatic hedging approach, in order to balance customers' risk tolerances with out-of-market outcomes.[61]

With regard to providing optional alternative rate offerings to customers, Aether recommends that FEI not provide any fixed or capped rate products but instead provide market price protection through its default commodity rate offering. This is largely because of the general lack of understanding by customers of their natural gas bills and the natural gas marketplace and the education and communication that would be required to inform customers of the new options. The declining share of natural gas marketers providing optional fixed rate offerings under the Customer Choice program suggests that many customers are now wary of locking into fixed rates for extended periods of time with marketers.

As the research indicates, customers prefer some rate stability but not at the expense of foregoing lower rates should the market price environment change. The FEI commodity rate offering, with more enhanced price risk management, can provide this for customers. With more customer research, as discussed above, FEI can target its price risk management strategies based on customers' rate or bill tolerances. Should some customers prefer absolute rate certainty, they can select to purchase their commodity supply from a natural gas marketer.

Aether believes that an opt-out option for those customers wanting a variable commodity rate without the proposed price protection strategies of the FEI default commodity rate offering is more appropriate than FEI attempting to provide fixed or capped rate options for customers. This would provide customers with an alternative to the FEI commodity rate and the fixed rate offerings from marketers.

FEI has concerns with providing an alternative opt-out variable commodity rate offering for customers. Due to the general lack of understanding of the gas markets and rate setting mechanisms, FEI believes that such an offering would only lead to confusion amongst customers as well as potential regret by customers later on if market prices were to move higher or become more volatile. Therefore, FEI does not recommend pursuing this option.

Aether suggests that FEI consider longer term price risk management opportunities given market prices are favourable relative to historical averages and supply and demand factors suggest rising gas prices in the future. FEI agrees with Aether in this regard given its assessment of the current market price environment and the potential for future natural gas demand as discussed in Section 4.2 and Appendix A.

Tools to mitigate longer term price risk include long term fixed price contracts, VPPs and investment in gas reserves. Long term fixed price contracts typically cover a period of up to ten years and are relatively easy to execute compared to VPPs or investing in reserves. Not only do they provide price stability but they also provide security of supply. When choosing between longer-term tools, such as VPPs and investing in reserves, Aether recommends VPPs for FEI. While investing in reserves includes some production and operating cost risks, VPP

[61] FEI and FEVI Review of Price Risk Management Objectives and Hedging Strategy dated January 27, 2011, Appendix A RiskCentrix Findings and Recommendations Report, page 13.

arrangements include fixed production and delivery costs, which more closely resembles FEI's current gas supply contracts and field of expertise. On a net present value basis, these types of contracts could be favourable relative to FEI's recent historical commodity rates, locking in secure, relatively low-priced supply for the long term for customers.

9. FEI RECOMMENDATIONS

FEI recommends more comprehensive price risk management to meet the objectives of mitigating market price volatility to support rate stability and capturing opportunities to provide customers with more affordable and competitive rates. This includes a portfolio approach using a full suite of tools and mechanisms for the short, medium and long term. This portfolio should include the use of physical natural gas storage, deferral accounts and rate setting mechanisms, fixed rate offerings provided by gas marketers and the EPP as well as physical and financial instruments. This strategy is based on the assessment of the natural gas market price environment, the tools and strategies available to FEI for price risk management, the recommendations of Aether and RiskCentrix, the customer research regarding preferences and bill tolerances and the Panel's directives following the review of FEI's hedging objectives and strategies.

More specifically, FEI recommends continuing with the following as part of its current price risk management strategy:

- Managing price risk through the ACP, including:
  - Seeking cost effective opportunities to increase natural gas storage;
  - Mitigating Sumas price disconnection risk by reducing Huntingdon supply, and
  - Using a mix of monthly and daily priced supply purchases.
- Using gas cost deferral accounts and quarterly rate setting mechanism to help mitigate short term market price volatility
- Providing customers optional rate and bill smoothing mechanisms such as:
  - The Customer Choice program fixed price commodity rate offerings provided by natural gas marketers
  - The Equal Payment Plan to smooth bill payments.

These tools and mechanisms have worked well over time in mitigating shorter term market price volatility, ensuring security of supply and providing customers with options to further reduce their rate and bill fluctuations if they choose to do so.

With regard to the use of deferral accounts, FEI recommends consideration of amortizing projected gas cost and deferral account balances over a twelve month as well as twenty four month period when setting commodity rates. This could help with managing deferral account balances within a reasonable +/- $50 million range and mitigating rate volatility, especially when there are large differences in projected costs between the forward first and second years.

FEI also recommends adding the following for a more comprehensive price risk management portfolio:

- Re-institute a medium-term (i.e. three years out) hedging program to protect customers from market price volatility. This should include further customer research and analysis:
  - Conduct further research to determine customer rate or bill tolerances
  - Conduct scenario and/or VaR analysis to help determine amounts and types of hedging to meet the objectives
- Consider longer term price risk management tools including:
  - Long term fixed price contracts
  - Volumetric production payment arrangements

FEI believes that this portfolio approach, utilizing physical, financial and rate setting mechanisms, along with optional rate and bill smoothing choices for customers, provides an effective way of meeting the objectives. This is because all of these tools and mechanisms have different attributes and act in different ways and no single tool or mechanism can effectively meet all the objectives in all market price environments.

FEI believes that re-instituting a medium term hedging program is appropriate given customers' preferences and tolerances for rate and bill changes and the potential for future market price increases and volatility. Any recommended hedging program should take the customer research preferences into account and, as such, target less than 100 percent of hedged consumption. This would balance customers' preferences for both market price and volatility protection with downward price participation. More frequent customer research and scenario and/or VaR analysis would help FEI develop specific hedging targets and selection of hedging instruments in different market price environments.

Given forward gas market price levels, FEI believes that consideration should be given to longer term price risk management opportunities. Long term fixed price contracts and VPPs would help mitigate longer term market price volatility, preserve lower commodity rates relative to historical values and ensure security of supply. FEI believes these tools are consistent with the Panel's directives in the Review. FEI believes that VPPs and long term fixed price contracts, rather than investing in reserves, are more consistent with FEI's level of expertise and risk profile.

In terms of providing choice for customers, FEI believes that there is not enough evidence to support FBC providing alternative commodity rate offerings. The difficulty in providing any alternative offerings, whether fixed, capped or variable, lies in customers' low level of understanding regarding gas markets, especially market price volatility and the ability to assess alternative products. FEI does not believe that the uptake for such optional offerings would justify the expense and effort in terms of customer communication, education and required support systems. FEI believes that it should mitigate market price volatility on a portfolio basis for all of its commodity customers through its default commodity rate offering, which provides an appropriate balance of price protection and market price signals. Should customers desire a higher amount of rate stability, they can opt for the marketers' fixed rate offerings.

10. NEXT STEPS

Based on the Panel directives related to the Review, the current market price environment, the customer research and FEI's assessment of price risk management alternatives, FEI believes that a more comprehensive price risk management strategy is warranted to meet the objectives on behalf of customers. FEI has provided some recommendations within this report, which are based on assessments by FEI as well as the independent assessments by Aether and RiskCentrix.

In discussions with Commission staff on September 11, 2014 regarding price risk management, FEI proposed a consultative approach to reviewing the recommendations and developing specific requests for approval. FEI suggests that the recommendations within this review report be discussed with Commission staff and stakeholders through a collaborative utility workshop approach. The objective of the workshops would be to develop mutually agreeable price risk management strategies for customers and to develop specific requests, which FEI would then submit to the Commission for approval. FEI recommends a series of half day meetings led by FEI representatives providing relevant background material and information and facilitating the discussions with stakeholders. FEI believes this process will enable full discussion of the issues and address any potential concerns of stakeholders and hopefully lead to some common ground in terms of price risk management objectives and strategies. For example, the proposed topics for discussion could include the following:

- Panel Review decision;
- Price risk management objectives;
- Current FEI rate structure and rate setting mechanism;
- Natural gas market overview;
- Customer research;
- Other utilities' price risk management;
- Recommendations for more comprehensive price risk management, and
- Development of requests for approval.

The workshops may also include presentations by the consultant, Aether, to provide their independent views and recommendations.

If mutually agreed-upon requests for approval are developed, FEI would then submit them in a separate filing to the Commission for approval.

11. CONCLUSION

The natural gas marketplace has undergone significant changes during the past few years. The abundance of shale gas and weakened demand following the recession which started in 2008 has led to a steady decline in natural gas prices from 2008 to 2012. With one of the warmest winters on record in 2011/12, spot gas prices fell in mid-2012 to their lowest levels in over a decade.

However, since that time, changes have occurred in terms of both supply and demand in the gas marketplace and prices have since increased from the lows seen in 2012. In particular, during winter 2013/14, despite near-record levels of natural gas production, demand soared and market prices responded. While Henry Hub spot prices increased to their highest level in over five years, Sumas prices spiked to levels not seen since 2000 and AECO/NIT and Station 2 prices rose to their highest levels ever. After several years of declining market prices and FEI commodity rates from 2008 to 2012, FEI has since had two significant commodity rate increases, one effective July 1, 2013 and another effective April 1, 2014.

Spot market prices have subsequently decreased as mild summer 2014 weather and natural gas storage levels have largely recovered from their low levels at the end of winter 2013/14. While a cold 2014/15 winter may again increase prices and volatility, a warmer-than-expected winter may lead to lower prices and provide opportunities to capture favourable market prices for customers.

Within the next few years, natural gas demand is expected to increase in response to the relatively low North American gas prices and environmental requirements. For example, the retirement of many coal plants, resurgence in industrial activity and the potential for LNG exports will boost natural gas demand, especially during the latter part of this decade. While there is plenty of natural gas supply potential in North America to meet this future growth in demand, it will be developed and produced at a higher cost.

The customer research conducted recently is consistent with previous research and indicates that gas consumers prefer some level of rate stability. The 2005 survey information shows that customers have tolerances in terms of annual rate or bill changes. FEI believes that further research in this regard can provide more insight into these tolerances and help define hedging parameters. Those customers wanting absolute rate certainty can select the fixed rate offerings provided by natural gas marketers under the Customer Choice Program. However, for the majority of gas customers, the FEI default commodity rate can provide customers with the balance of market price protection and downside price participation.

Based on these considerations, the Panel's directives and the assessments by Aether and RiskCentrix, FEI believes it is time for more comprehensive price risk management. Not only will this provide the medium term price protection customers prefer, but it will also provide the opportunity to help preserve lower commodity rates for customers and secure cost effective supply over the longer term. With the Commission decision regarding the Amalgamation

Decision, the propose price risk management strategy will provide benefits to all of the amalgamated gas entity customers.

This Review Report provides a framework for discussing the recommendations with Commission staff and stakeholders through a collaborative workshop approach. FEI hopes that a consultative approach with stakeholders will lead to a common understanding and agreement of the objectives and strategies and help formulate plans which are responsive to changing market conditions and which meet the objectives in the interests of customers.

Appendix A

NORTH AMERICAN GAS MARKET OVERVIEW

1. INTRODUCTION

Significant changes have occurred in the North American natural gas market over the past few years. Advances in drilling technology and cost reductions for producers have led to an abundance of gas supply, which is expected to continue to rise. The abundance of gas produced from shale formations has also caused natural gas commodity prices to drop considerably from historical highs. This change has also created opportunities for increased natural gas use, particularly in power generation and the industrial sector, LNG export markets, and the transportation sector. It is this increase in demand that will lead to higher market prices in the future.

Although gas prices have dropped over the past few years, the market saw prices and volatility increase in winter 2013/14 compared to levels in 2012 and 2013, as North America experienced one of the coldest winters in decades. The extremely cold temperatures caused record demand for gas, resulting in U.S. and Canadian natural gas storage inventory levels to fall to a 10-year low. Concerns about falling storage levels also contributed to keeping gas prices high throughout winter 2013/14, as well as throughout the spring of 2014. However, market prices have subsequently decreased as natural gas storage levels have largely recovered from their low levels at the end of winter 2013/14. While a cold 2014/15 winter may again increase prices and volatility, a warmer-than-expected winter may lead to lower prices and provide opportunities to capture favourable market prices for customers.

Over the longer term, higher gas prices are expected as increased demand absorbs excess supply. This shift in demand comes primarily from retirement of coal plants, increased power generation demand, increased industrial activities, LNG exports, increasing exports to Mexico, and the greater use of natural gas for transportation. In order to meet this expected demand, producers will need to see higher sustained gas prices before they will commit new capital needed to increase production and/or to locate and develop new production sites.

This appendix provides an overview of the evolving natural gas market in North America, including natural gas supply, demand, storage and prices.

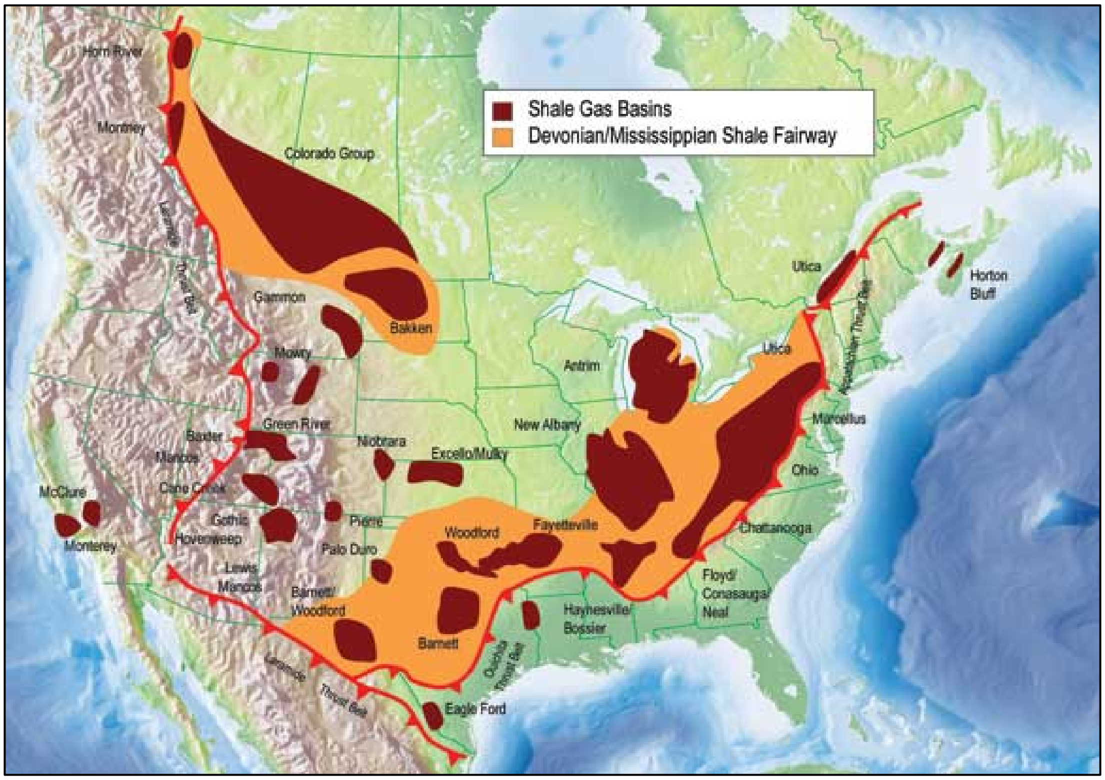
2. NATURAL GAS SUPPLY

The North American natural gas market has undergone significant changes in terms of supply over the past few years. Advances in drilling technology and significant cost reductions related to unconventional gas development, in particular shale gas, have created an abundance of gas supply in North America.

2.1 *NORTH AMERICAN SUPPLY RESERVE POTENTIAL*

Before the proliferation of shale gas, the gas industry believed that supply in North America was dwindling and the market would become more dependent on LNG imports. However, over the past five years, advances in technology and horizontal drilling have been able to unlock previously known natural gas reserves trapped in shale deposits all across North America. Producers are able to drill and produce gas more quickly and efficiently than ever before. Gas market analysts currently predict that North America holds over 100 years of economically recoverable supply based on current consumption levels. Not only is gas supply abundant, shale gas supplies are located throughout North America, providing cost effective supply within close proximity to many major load centres. Figure 1 shows the key North American shale gas regions.

Figure 1: North American Shale Gas Plays[1]



The Western Canadian Sedimentary Basin (WCSB), which extends from northeast B.C. to southwest Saskatchewan, also contains significant unconventional gas supplies and includes the Horn River, Montney, Liard, Cordova, and Duvernay gas plays. The WCSB is currently estimated to have 143 trillion cubic feet (Tcf) of marketable gas remaining (discovered and undiscovered) in place[2] while it was estimated to be only 87 Tcf five years ago.[3]

2.2 *U.S. PRODUCTION*

U.S. natural gas production continues to reach record levels, although the pace of production growth has slowed as producers have been shifting to more economically rewarding oil and liquids rich plays from dry gas plays in the face of low commodity prices. Current U.S. marketed natural gas production is above the levels experienced in the past five years, as depicted in Figure 2.

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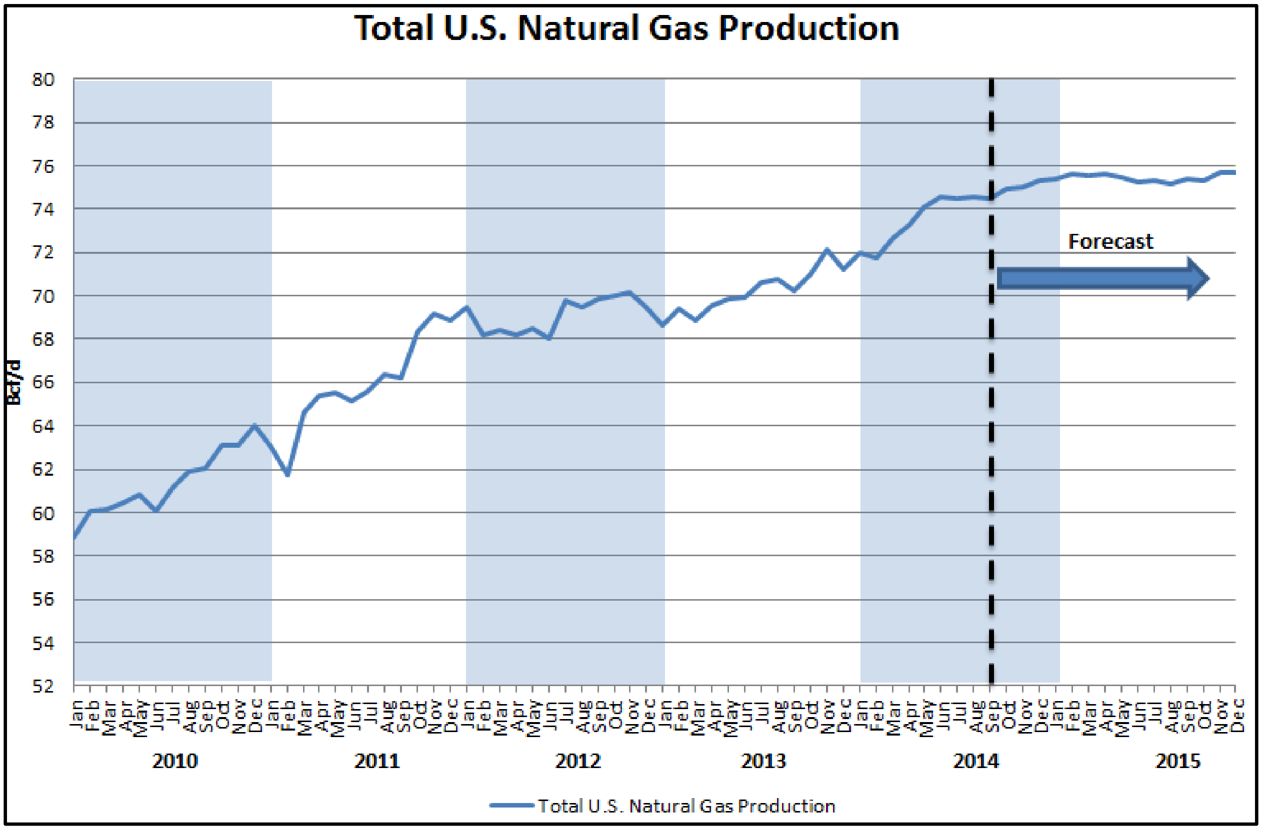
[1] National Energy Board, Understanding Canadian Shale Gas - Energy Brief
[2] National Energy Board, Energy Market Assessment, 2012-2014
[3] WCSB Royalty Income Investments, The Basin. http://www.wcsb.ca/learningcenter/thebasin.aspx

Figure 2: U.S. Natural Gas Production[4]

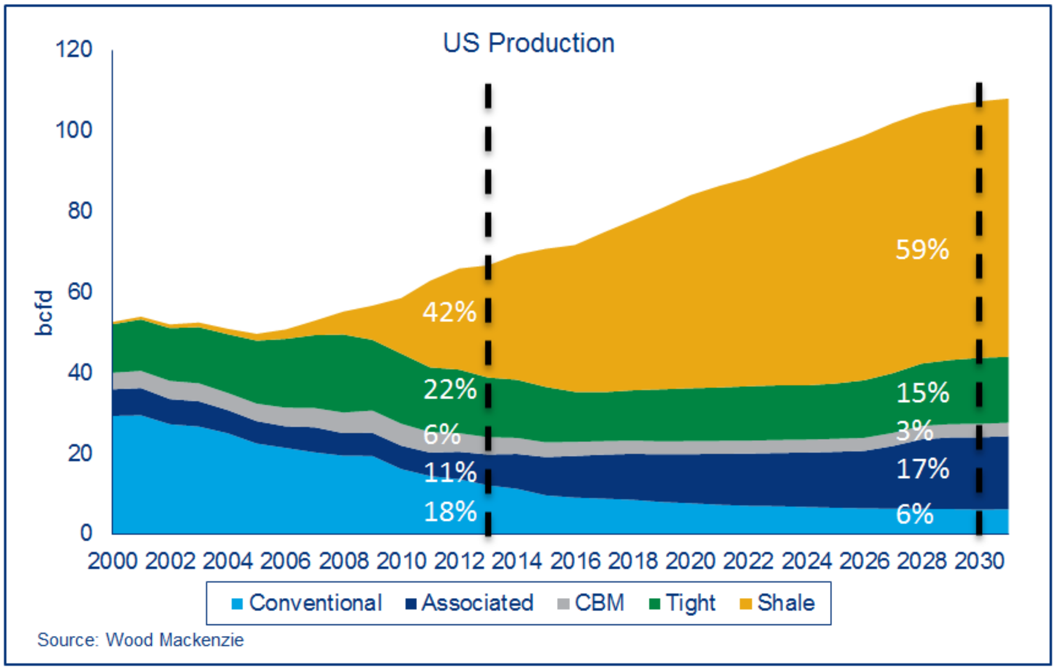


In August 2014, total U.S. production averaged about 74.6 Bcf/day, in comparison to the average production of 70.2 Bcf/day in 2013.[5] Despite relatively low gas prices, advances in drilling technology and efficiencies have resulted in steadily increasing production over the past few years. While supply is expected to remain high over the next few years relative to historical averages, supply growth has recently leveled off in response to low prices.

Over the long run, supplies from unconventional resources such as shales will be the single most significant contributor to growth in production and will eventually become the largest source of overall production. As illustrated in Figure 3, shale gas accounted for about 42% of U.S. production in 2013. However, by 2030, shales are expected to contribute about 59% to total U.S. natural gas production, while the production contribution from conventional gas plays is expected to decline from 18% currently to about 6% by 2030.

[4] U.S. Energy Information Administration, Short Term Energy Outlook, September 2014
[5] Ibid.

Figure 3: U.S. Production by Type[6]



2.3 *CANADIAN PRODUCTION*

In Canada, the majority of natural gas supply originates from the WCSB with smaller quantities originating in eastern Canada, particularly off the coast of Nova Scotia. In the short term, overall Canadian production is expected to remain relatively flat, as supply growth in the Montney, Horn River, Duvernay and Liard regions offsets declining production in Alberta. However, as illustrated in Figure 4, by 2030 production from shale gas plays is expected to make up about 64% (14.6 Bcf/d) of all Canadian production, as new infrastructure is built to connect supply to markets; an increase from the 20% (2.9 Bcf/d) that shale gas plays contribute today. Similar to U.S. production forecasts, supply from conventional sources will decrease, from 41% today to about 7% by 2030.

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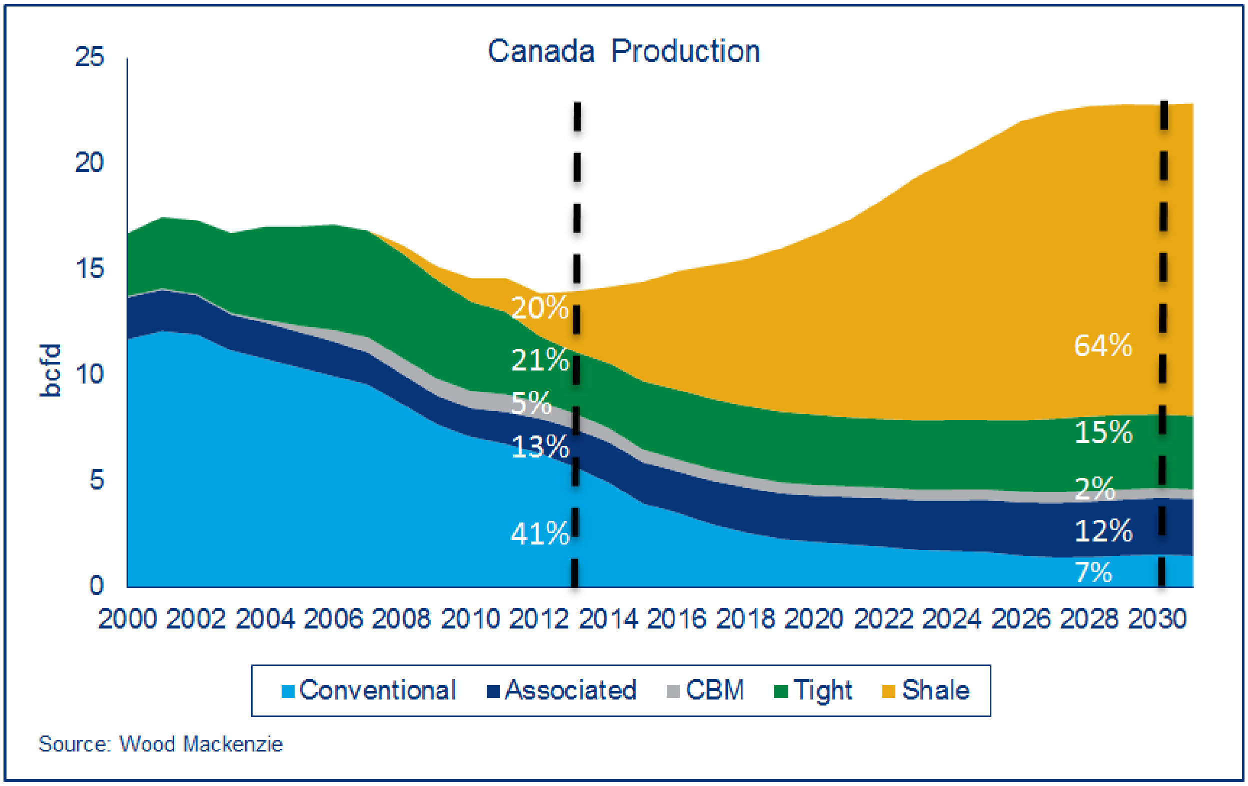
[6] Wood Mackenzie, North America Natural Gas Long-Term View, May 2014. CBM, coal bed methane, is natural gas extracted from coal bed formations. Tight gas is a form of unconventional supply that is extracted from rock and sand formations. Associated gas supply is extracted during petroleum (oil) production. Shale gas is natural gas produced from the fractures, pore spaces, and physical matrix of rock shale.

Figure 4: Canadian Natural Gas Production Forecast[7]

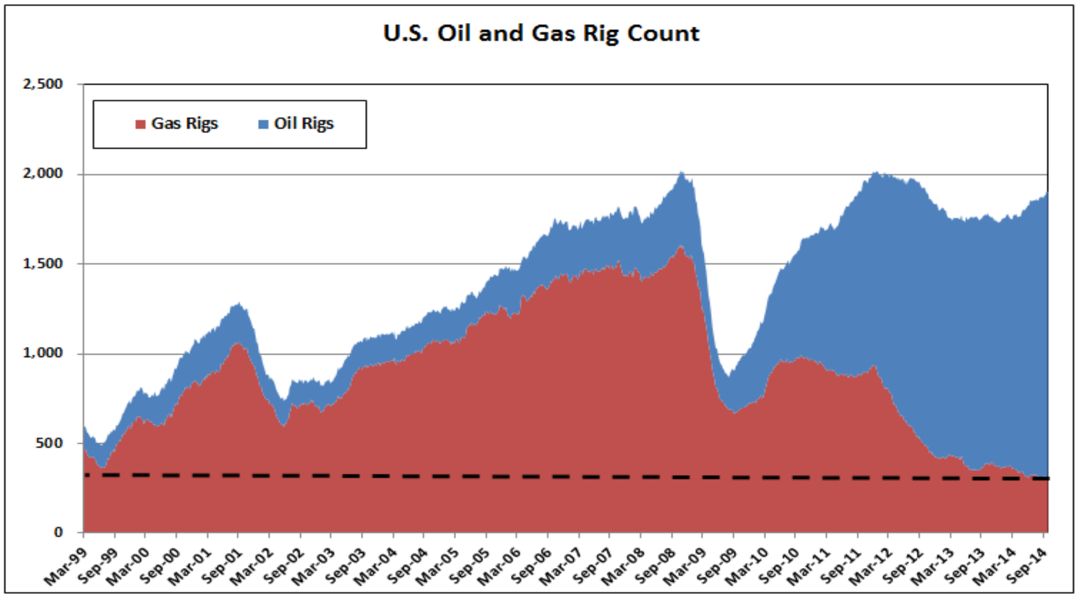


2.4 PRODUCTION SHIFT FROM DRY GAS TO OIL AND LIQUIDS RICH PLAYS

Although overall North American production levels have continued to grow, the rate of natural gas production growth has slowed as natural gas producers reduced dry gas development in response to low natural gas commodity prices. Relatively higher natural gas liquids prices, which are tied to oil prices, provide producers with a strong economic incentive to shift development activity from dry gas to oil and liquids-rich drilling. Figure 5 illustrates this shift in development activity in the movement of drilling rigs from natural gas to oil over the past number of years. This shift to more oil drilling has helped to rebalance supply of the natural gas market, as production growth has slowed while demand continued to increase.

[7] Wood Mackenzie, North America Natural Gas Long-Term View, May 2014

Figure 5: North American Oil and Gas Drilling Rig Count[8]



With oil and liquids-rich drilling associated gas is often produced as a by-product, which also contributes to the level of overall gas production. However, despite the supply from associated gas production, it is not expected to offset the overall reduction in dry gas production growth in the near term. Over the longer term, with increased demand for natural gas and an increase in market prices, it is expected that gas producers will need to return to dry gas drilling and as a result total gas supply will also increase.

Importantly, for many gas producers, they have been able to continue to produce in the low price environment that has existed over the last few years because of favourable returns from a combination of liquids-rich gas production and favourably hedged gas commodity prices on a portion of their production.

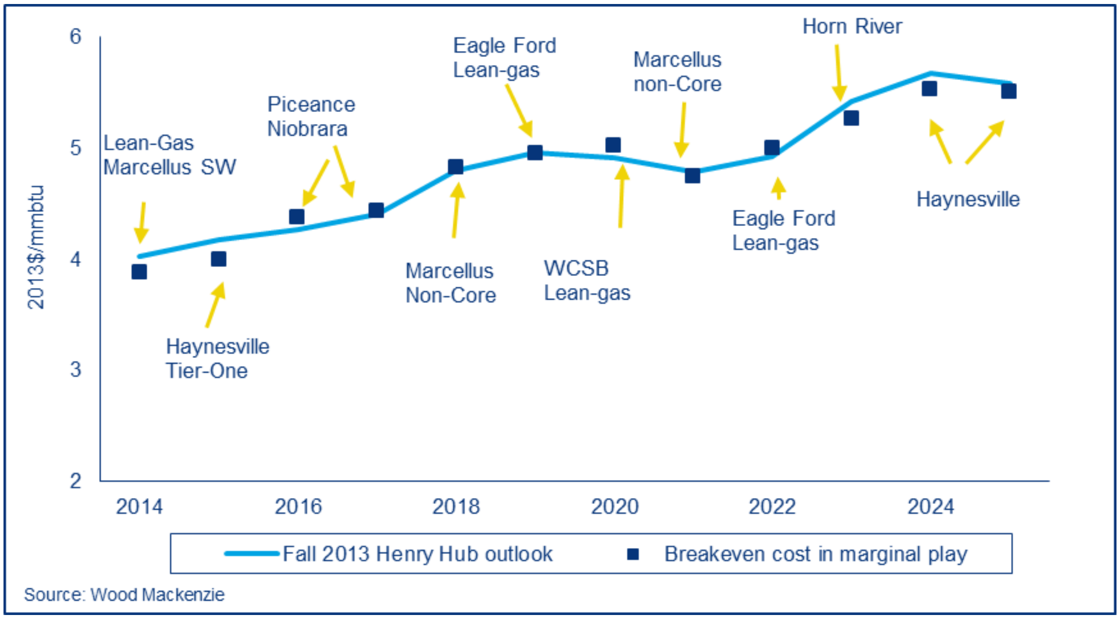
2.5 *PRODUCER BREAKEVEN COSTS*

The current low gas price environment is challenging some producers to recover their breakeven costs for drilling and exploration of wells, particularly in the dry gas regions. Market prices below breakeven costs have forced producers to either reduce, shut-in production, or shift development away from gas to oil and liquids. Figure 6 illustrates the breakeven cost of developing various marginal gas plays in NorthnAmerica. Although there is an abundance of gas available in North America, higher market prices are needed for producers to return to dry gas drilling. As of October 1 2014, the NYMEX future prompt month (November) settled at $4.02 US/MMBtu while the three-year price average from Novemeber 2014 to October 2017 is about $4.04 US/MMBtu. Although prices have rebounded since 2012, they are still relatively

[8] Baker Hughes Rig Count Service

low to incent producers to develop more gas. For instance, ConocoPhillips, one of the largest gas producers in North America, recently stated that they need to see gas prices stay over $5/MMBtu for as long as two years before the company would begin to increase spending on natural gas.[9] Statement like this indicate that despite a rebound in gas prices in 2013 and 2014, many producers are not expecting to return to dry gas drilling or increase drilling until the market reaches a relatively higher sustained pricing environment.

Figure 6: Marginal Play and Price Outlook[10]

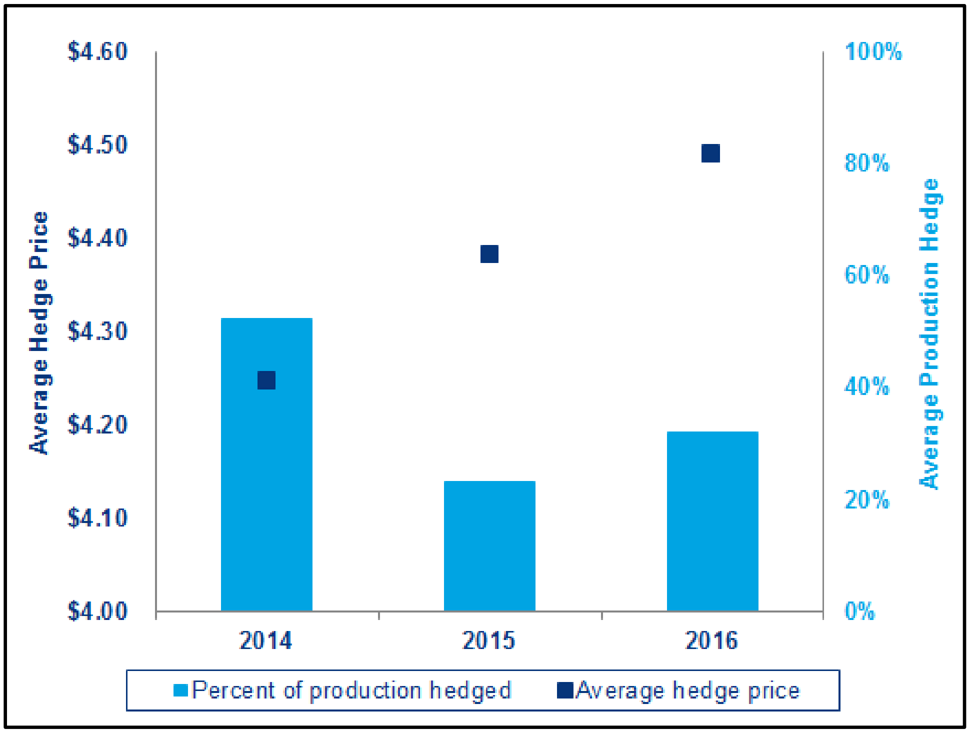


2.6 *PRODUCER HEDGES*

Producers operating in the US have taken advantage of the recent higher gas prices and the volatility caused by the cold winter of 2013/14. They have transacted hedges that give them price certainty, as well as some rate of return, thereby enabling them to continue some gas drilling. As Figure 7 illustrates, producers had about 52% of production hedged for the remainder of 2014 at an average hedge price of about $4.25 US/MMBtu. Looking forward, producers have currently hedged about 23% of their production at an average price of about $4.38 US/MMBtu for 2015 and about 32% hedged at an average price of about $4.49 US/MMBtu for 2016. Due to a reduced level of hedges in the future, market prices will have more of an impact on producer profit margins in 2015 and 2016.

[9] http://business.financialpost.com/2014/02/10/natural-gas-drillers-wary-as-some-see-year-long-supply-squeeze/?__lsa=88d2-7481
[10] Wood Mackenzie "United States Gas Markets Long-Term Outlook H2 2013" – Chart 5

Figure 7: Average U.S. Hedging Levels and Hedged Prices for Surveyed Producers[11]



2.7 *RECENT PRODUCER CUTBACKS TO PRODUCTION*

In light of low gas prices in the past few years, which have been lower than or near many breakeven costs for marginal dry gas plays, some producers have begun to cut back on dry gas production. Chesapeake Energy, one of the largest natural gas producers in North America has been affected by the low gas prices and decided in 2012 to cut over 1 Bcf/day of their gas production and reduced their number of gas rigs from 47 to 24 in 2012.[12] Moreover, producers in the Horn River region of B.C., such as Encana, have announced reductions to production targets in response to current gas prices as well.[13] Encana plans to exit a number of its 28 plays in North America, as a shift of focus from dry gas to higher value crude oil and liquids rich gas, in response to the low natural gas pricing environment.

In December 2013, Encana announced that it would focus the majority of its 2014 spending, about $2.5 billion, on five oil and liquids-rich plays, including the Montney in B.C., the Duvernay in Alberta, DJ Basin in Colorado, San Juan Basin in New Mexico, and Tuscaloosa Marine Shale in Louisiana and Mississippi. In March 2014, Encana announced the $1.8-billion sale of the Jonah gas field in Wyoming to further support the transition strategy to a higher liquids-weighted production base.[14] In September 2014, Encana announced it would acquire Texas-based

[11] Wood Mackenzie, North America Natural Gas Service, April 2014
[12] Globe and Mail, “Chesapeake Energy cuts natural gas production,” Jan 23 2012.
[13] CBC News, “Encana announces $2.9B asset sale,” February 17, 2012
[14] Calgary Herald, “Ewart: Encana finding its focus,” April 1, 2014

producer Athlon Energy for $7.1-billion, adding 140,000 acres of land in the Permian basin, which is an oil-rich basin surrounding Midland, Texas, to Encana's portfolio.[15]

2.8 SUPPLY SUMMARY

Improvements in drilling technology and the reduction in gas production costs have provided North America with an abundance of natural gas supply. However, in response to relatively low gas prices and weak demand in recent years, gas supply growth has slowed, and producers have instead focused their drilling efforts on oil and liquids rich plays. While there is plenty of future supply available to meet demand, it will come at a higher cost. This abundance of supply has spurred changes in the marketplace and demand for natural gas is expected to grow. These demand factors are discussed in more detail in the following section.

15 http://business.financialpost.com/2014/09/29/encana-to-buy-texas-oil-play-athlon-energy-in-7-1-billion-deal/?lsa=84ca-54fe

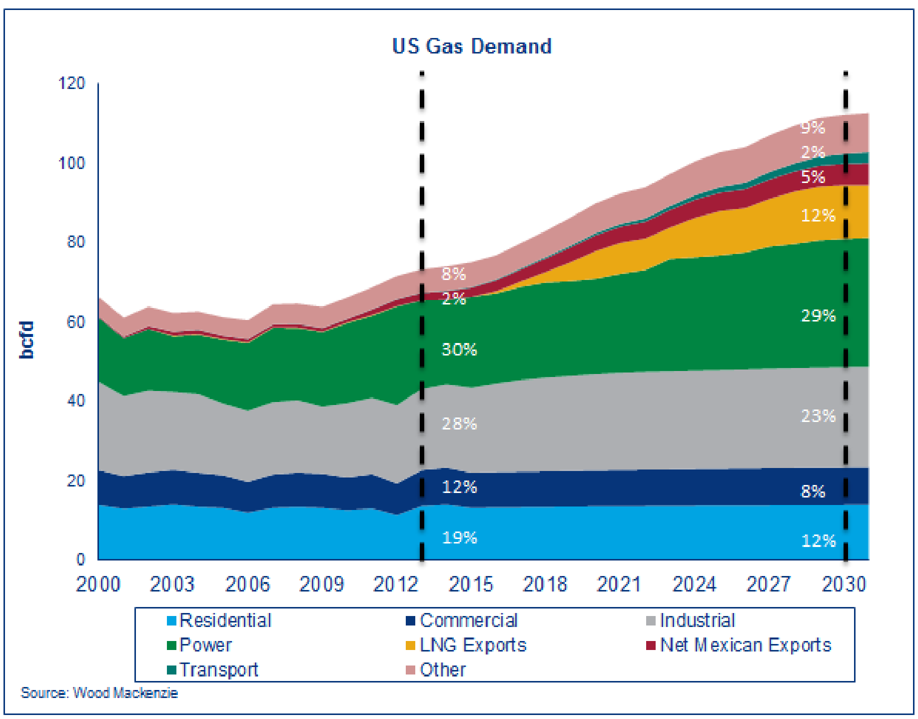
3. NATURAL GAS DEMAND

Low natural gas prices in recent years have provided incentives and opportunities for the greater use of natural gas across North America. Demand is recovering from the industrial sector, after being depressed prior to the past few years due to higher energy costs and reduced economic activities. Additionally, greater switching from coal to natural gas for power generation has occurred. The development of emerging markets such as LNG exports and, to a lesser degree, the natural gas for transportation (NGT) market will add to demand over the long run.

3.1 *U.S. GAS DEMAND*

Figure 8 provides a demand forecast for U.S. residential, commercial, industrial, power, NGT, Mexican export, LNG export demand, and other demand components (including lease, plant, and pipeline fuel) out to 2030. Demand in the longer term is expected to grow steadily, with gas demand for power generation expected to be the largest contributor to overall demand in 2030 as coal-fired power plants are retired and being replaced, to a large degree, with gas fired generation. In addition, the development of the LNG export sector is expected to eventually account for about 12% of total U.S. gas demand by 2030.

Figure 8: U.S. Natural Gas Demand[16]



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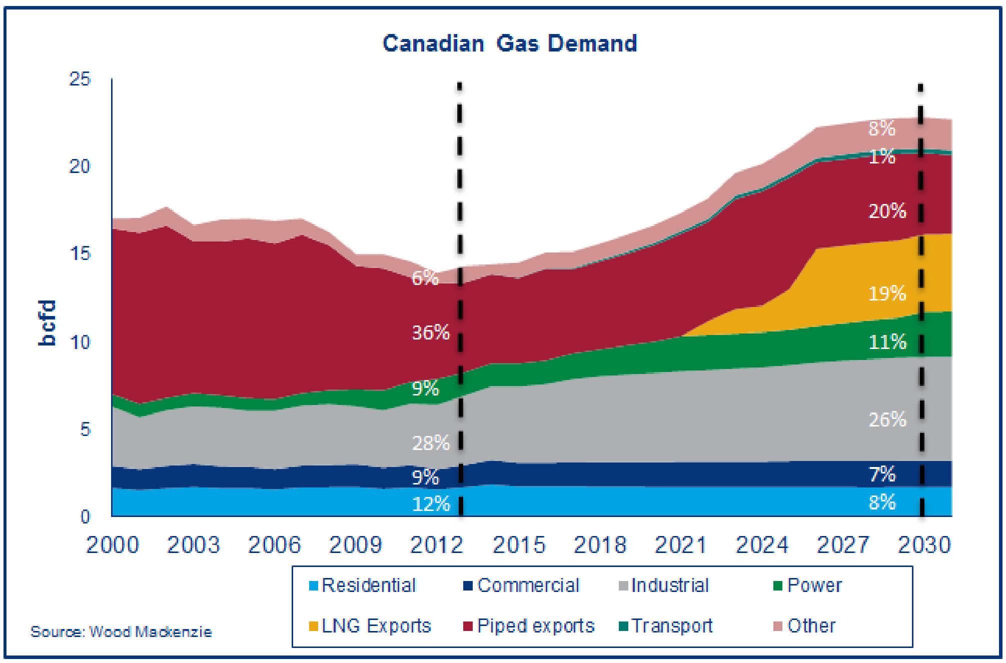
[16] Wood Mackenzie, North America Natural Gas Long-Term View, May 2014. 'Other' demand includes gas demand for lease, plant, and pipeline fuel.

In 2012, statements made by U.S. President Obama promoting the use of natural gas, particularly for NGT and other transportation uses, highlighted the importance of natural gas in meeting domestic energy needs and favourably positioned natural gas for the future. In particular, on January 24, 2012, he stated in his State of the Union Address, "my administration will take every possible action to safely develop this energy [natural gas], and my administration will work with private companies to develop up to five natural gas corridors along the nation's highways to build NGT fuelling stations." More recently, Obama promoted the U.S. government's "all-of-the-above" energy strategy including natural gas as "the bridge fuel that can power our economy with less of the carbon pollution that causes climate change."[17]

3.2 *CANADIAN GAS DEMAND*

Figure 9 illustrates a similar story to the U.S. for Canadian natural gas demand out to 2030. While there will be more demand attributed to power generation, the majority of the demand growth in Canada will come from the industrial sector, mainly for oil sands production in Alberta. It is expected that gas demand for LNG exports could grow to about 19% of overall Canadian gas demand by 2030.

Figure 9: Canadian Natural Gas Demand[18]



The Province of B.C. has been in support of developing markets for natural gas, particularly the LNG industry. The B.C. provincial government's aspiration to build a LNG industry has been

[17] http://www.nationaljournal.com/state-of-the-union-2014/obama-in-speech-defends-all-of-the-above-energy-plan-20140128

[18] Wood Mackenzie, North America Natural Gas Long-Term View, May 2014. 'Other' demand includes gas demand for lease, plant, and pipeline fuel.

prevalent for the last couple of years. In 2012, the B.C. provincial government released a report titled "B.C.'s Liquefied Natural Gas Strategy" which discussed the new development of using natural gas as an export fuel in the global LNG market.[19] More recently, the B.C. provincial government released a follow up report titled, "LNG – British Columbia's Liquefied Natural Gas Strategy One Year Update", which discussed the significant progress they have made over the year since they released their original LNG strategy, and how all signs are "currently pointing to British Columbia taking its place among the global leaders in natural gas production and export." [20] The B.C. provincial government has shown the commitment and determination to get the LNG industry up and running. In June 2013, the Globe and Mail reported that the B.C. provincial government reversed a key environmental policy by deeming natural gas a clean source of energy for LNG exports.[21]

In November 2013, the B.C. Government announced its support for FEI's investment of up to $400 million in the expansion of the Tilbury LNG facility. The provincial government granted approval for FEI to expand its Tilbury LNG facility, and announced that it will update the greenhouse gas reduction regulation, to increase the adoption of natural gas in B.C.'s transportation sector.[22] Bill Bennett, the Minister of Energy and Mines, stated these changes were made because the "government wanted to get out of the way and allow the transportation fuel component of the LNG industry to develop quickly." [23] The promotion of natural gas by local and federal governmental bodies positions natural gas in a favourable light and will contribute to increased natural gas demand in the future.

3.3 *POWER GENERATION DEMAND*

An increased focus on controlling greenhouse gas emissions (GHG) in North America will result in the continued retirement of older and less efficient coal-fired power plants and replacing them with relatively cleaner burning natural gas fired power generation facilities.

In the short term, existing gas fired generation will be dispatched over coal-fired generation when gas prices remain competitive with coal prices. This is because some power generators have the ability to switch between dispatching plants that use natural gas versus those that run on coal in response to market price signals. As illustrated in Figure 10, the EIA expects natural gas consumption in the power sector to increase from an average of 21.9 Bcf/day in 2014 to 22.7 Bcf/day in 2015.

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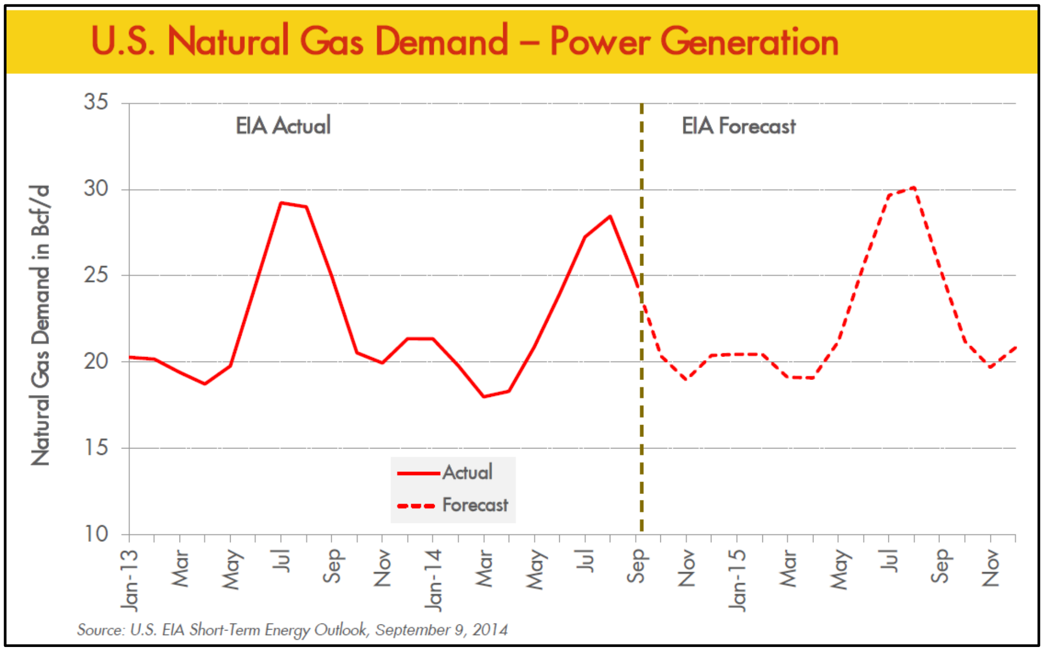
[19] Provincial Government of B.C., "LNG – Liquefied Natural Gas Strategy for B.C.'s Newest Industry"
[20] Provincial Government of B.C., "LNG – British Columbia's Liquefied Natural Gas Strategy – One Year Update"
[21] Globe and Mail "B.C. Liberals declare natural gas a clean energy source" http://www.theglobeandmail.com/news/british-columbia/bc-liberals-declare-natural-gas-a-clean-energy-source/article4362331/
[22] $400-million investment in LNG creates B.C. jobs – BC Government News Release – Nov 28, 2013.
[23] $400-million investment in LNG creates B.C. jobs – BC Government News Release – Nov 28, 2013.

Figure 10: Natural Gas Demand for Power Generation[24]



Over the long run, the largest contributor to gas demand in North America is expected to come from the retirement of existing coal-fired power generation.

U.S. coal-fired power plants are subject to the Mercury and Air Toxics Standards (MATS), which require significant reductions in emissions of mercury, acid gases, and toxic metals. The standards are scheduled to take effect in April 2015, but some plants are conditionally allowed to be extended by up to one year.

Furthermore, the U.S. Environmental Protection Agency (EPA) released the Clean Power Plan in June 2014, targeting carbon pollution reduction for existing fossil fuel based power generating plants[25]. The regulation provides state-specific emmission reduction targets and includes some guidelines, such as improving plant efficiency or increasing renewables. The states are required to submit their plans for meeting the targets by June 2016. The result of this Clean Power Plan will likely be less reliance on coal-fueled power generation and a greater share for natural gas and renewable sources of energy in U.S. power generation in the future.

As illustrated in Figure 11, EIA's latest forecast in Annual Energy Outlook 2014 projects 90% of the U.S. coal-fired capacity retirements would occur by 2016, above the retirement capacity previously reported to EIA as planned by power plant owners and operators in December 2013.

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[24] EIA/Shell Energy, Monthly US Gas Fundamentals – September 2014
[25] http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan-flexibility

Figure 11: Projected Cumulative Retirements of Coal-Fired Generating Capacity[26]

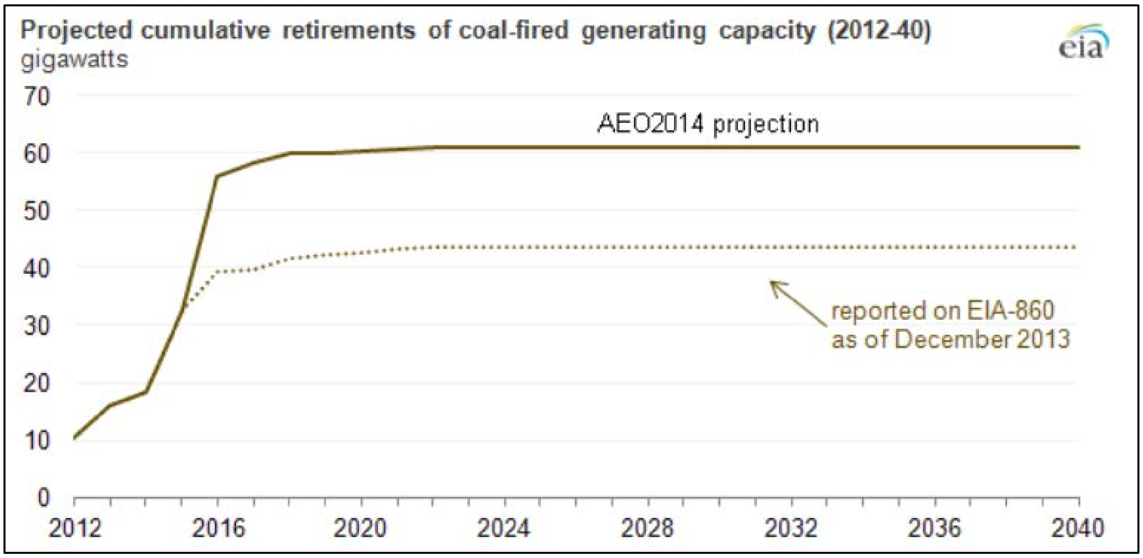
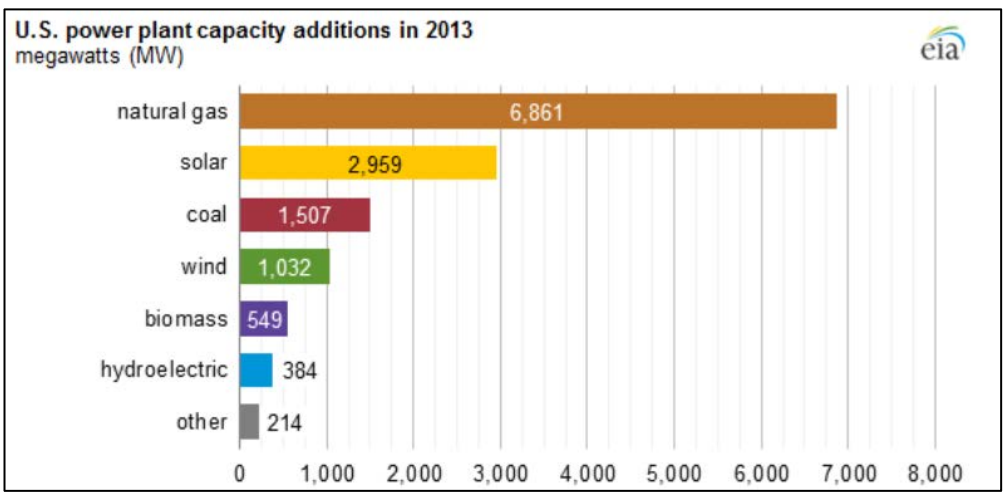


Figure 12 depicts the demand by fuel type for all new capacity additions for power generation in 2013. As presented, natural gas-fired power plants accounted for about 50% of the new power generation capacity added in 2013 and this trend is expected to continue.

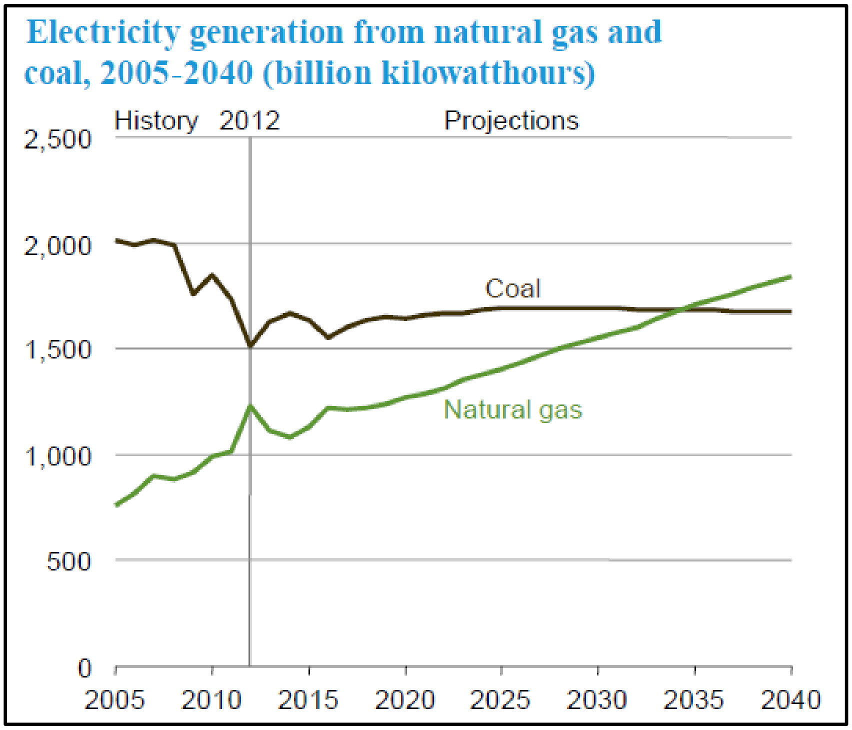
Figure 12: Capacity Additions for Power Generation by Fuel Type (MW)[27]



As illustrated in Figure 13, natural gas is expected to overtake coal to provide the largest share of U.S. electric power generation. In 2040, natural gas is expected to account for 35% of total U.S. electricity generation, compared to 32% only for coal.

26 http://www.eia.gov/todayinenergy/detail.cfm?id=15031
27 EIA, Annual Energy Outlook 2014 ER

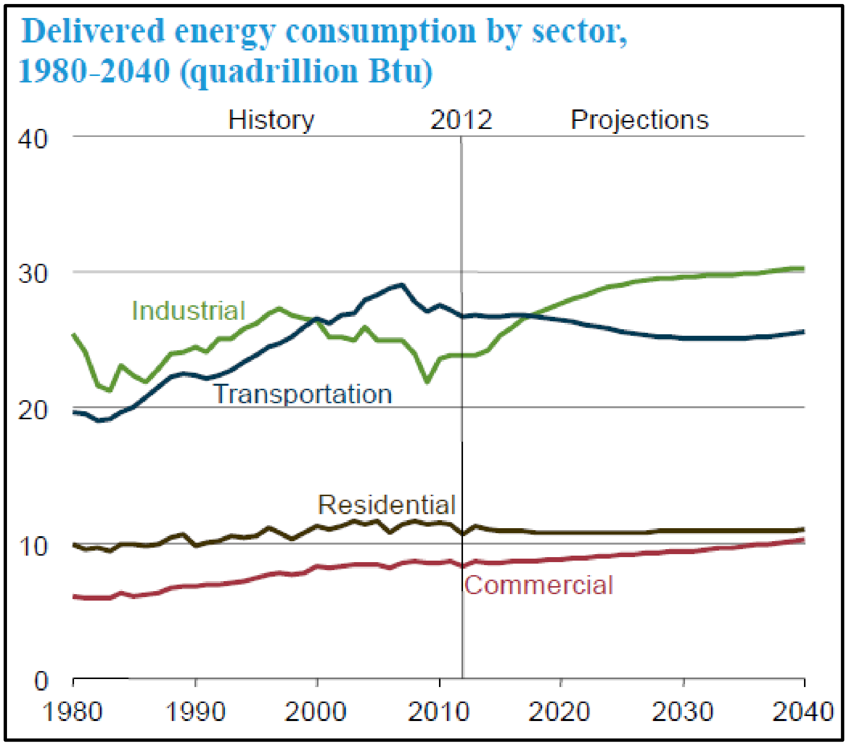
Figure 13: Electricity Generation from Natural Gas and Coal



3.4 *INDUSTRIAL DEMAND*

Another source of gas demand in North America that is expected to continue increasing in the future is demand from the industrial sector. As illustrated in Figure 14, approximately one-third of total U.S. delivered energy in 2012 was consumed in the industrial sector, which includes manufacturing, agriculture, construction, and mining. As economic conditions gradually improve and industries take advantage of the low priced natural gas supply, the industrial sector becomes the largest energy consuming sector in U.S. by 2018.

Figure 14: Projected Energy Consumption by Sector[28]



With current low gas feedstock prices, the competitiveness of North American industrial companies is improving for sectors such as the petrochemical and fertilizer industries. In addition to increased manufacturing, other gas intensive industries include iron and steel, cement and methanol production.

According to estimates by analysts, there are over 120 projects in North America in various stages of development that could potentially be built to take advantage of relatively cheaper feedstock natural gas prices, with most of them in Texas and along the Gulf Coast.[29] These projects are estimated to cost up to $80 billion in new construction and expansions of existing infrastructure into 2018. An example of one of these is the project by Sasol to construct a gas-to-liquids plant that is scheduled to come online by 2018 and could add up to 835,000 MMcf/day of industrial gas demand. Other large projects include CF Industries' nitrogen fertilizer plant and Potash Corp.'s restart of its anhydrous ammonia plant in Louisiana.

Furthermore, some companies are assessing the feasibility of bringing manufacturing operations back to the U.S. from overseas to take advantage of lower gas prices. One example is the German automaker, Daimler AG, who in December 2012 stated that it would like to

[28] EIA, Annual Energy Outlook 2014 ER
[29] Bentek Natural Gas Industry Analysis

expand its existing facility in Detroit and chose this site over others located in Mexico and Germany.[30]

With regard to the methanol industry, Methanex, the world's largest producer of methanol, restarted its facility in Medicine Hat, Alberta in 2011. This project consumes approximately 50,000 MMBtu of natural gas per day. Additionally, Methanex is also relocating one of its Chilean methanol facilities to Louisiana which is targeted to be operational by the end of 2014. Celanese Corp. has also said it will open a methanol production facility in Houston, Texas in 2015. There have also been developments in Washington and Oregon in which a multinational group of investors, including the Chinese Academy of Science and the British Petroleum Company (BP), are proposing to build a 1.8 billion dollar plant to convert natural gas to methanol at the Port of Tacoma.[31] The group of investors called Northwest Innovation Works is also planning similar plants at the Port of Kalama, Washington, and at Port Westward, Oregon. Carla Skaggs, spokeswomen for the company stated the three developments are "being driven by the abundance of relatively inexpensive new natural gas discoveries in the United States and Canada…and by the Chinese desire to reduce pollution in their country."[32] Although, the amount of natural gas needed for these projects has not yet been disclosed, Greg Peden, a partner at Gallatin Public Affairs, a Portland firm representing the venture, noted that each plant would produce 5,000 metric tons of methanol a day during the first phase.[33] These developments in the methanol segment of the industry could potentially add up to several hundred thousand MMBtu per day of gas demand to the North American market if they materialize.

It is estimated that if all proposed industrial additions are built that natural gas consumption could increase by up to 6 Bcf/day in the U.S. by 2020. However, it is unlikely that all proposed industrial expansions will be built and that actual demand growth will be slower than expected due to lack of access to capital and other factors.[34]

Oil Sands and Natural Gas Demand

A significant segment of Canadian industrial demand is from the oil sands of Alberta where natural gas is used in the extraction of crude oil. Key drivers that affect the development of the oil sands projects include the difference between natural gas and oil prices and the infrastructure required to transport gas to the oil sands and then to carry the bitumen away to markets.

Figure 15 illustrates the natural gas required to sustain the Canadian oil sands industry to 2046. By 2046, natural gas demand from oil sands is forecast to increase two to three times from the

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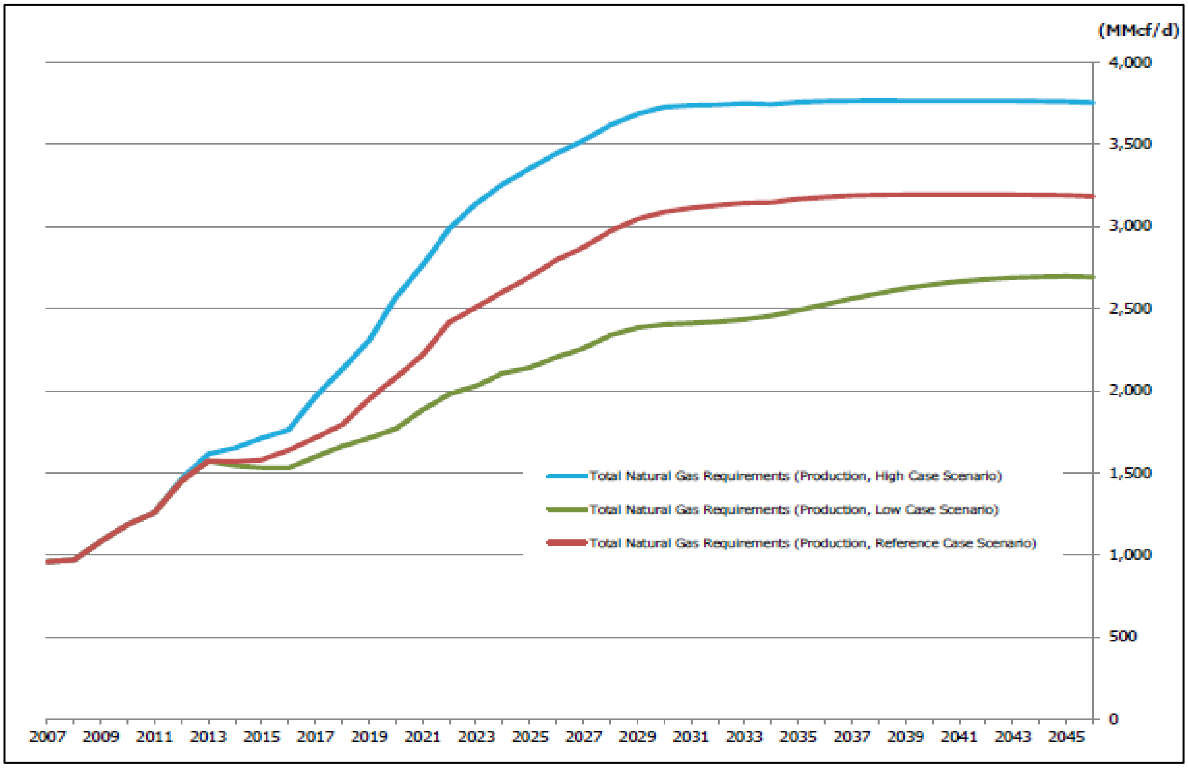
[30] Platts Gas Market Report, January 18, 2013
[31] "Multinational group proposes $1.8 billion gas-conversion plant in Tacoma." http://www.thenewstribune.com/2014/04/23/3163248/multinational-group-proposes-18.html
[32] "Backers say twin $1 billion methanol plants planned by China-backed joint venture would be safe and environmentally sound." http://www.oregonlive.com/business/index.ssf/2014/01/backers_say_twin_1_billion_met.html
[33] ibid
[34] Barclay's Natural Gas Report

2011 level of 1,259 MMcf/day, to 3,183 MMcf/day in the Reference Case Scenario, or 3,753 MMcf/day under the High Case Scenario.

Figure 15: Natural Gas Requirements for Canadian Oil Sands[35]



3.5 *NORTH AMERICAN LNG EXPORT DEMAND*

North American LNG exports also have the potential to provide significant demand for natural gas in the future. Countries in Europe and Asia have traditionally imported LNG from Australia and Qatar, with the imported LNG prices indexed to the crude oil prices and at higher prices than in North America.

Due to the shale gas development in North America and subsequent lower natural gas prices, the relative spread in gas prices between North America and Europe and Japan has widened over the last couple of years. Figure 16 below from the U.S. Federal Energy Regulatory Commission (FERC) shows estimated landed world LNG prices for September 2014 delivery for various import points around the world.

[35] Canadian Energy Research Institute, Canadian Oil Sands Supply Costs and Development Projects (2012-2046), May 2013

Figure 16: Global LNG Spot Prices ($US/MMBtu Equivalents)[36]

Many LNG export facilities have been proposed in recent years in the U.S.(Gulf of Mexico, Alaska, Oregon, and the east coast), as well as in Canada (mostly on the west coast of B.C.). However, due to resource and cost constraints, it is unlikely that all projects will proceed to completion.

Changes to the U.S. Department of Energy's LNG Export Decision-Making Procedures

On August 14, 2014, the U.S Department of Energy (DOE) finalized major changes to the review of applications to export LNG to Non-FTA countries. The DOE would no longer be issuing conditional approvals to export LNG, and would now only review applications that make a final public interest determination after the completion of the review required by environmental laws and regulations that are included in the National Environmental Policy Act (NEPA) review .[37] The DOE noted that the change was implemented to "streamline the regulatory process for applicants, ensure that applications that have completed NEPA review will not be delayed by their position in the current order of precedence, and give the department a more complete understanding of project impacts."[38] As set out in Table 1, there were eight U.S LNG export projects that had already received approval to export LNG to non-Free Trade Agreement

[36] Federal Energy Regulatory Commission, Market Oversight, October 2014, http://www.ferc.gov/market-oversight/mkt-gas/overview/ngas-ovr-lng-wld-pr-est.pdf

[37] A Proposed Change to the Energy Department's LNG Export Decision-Making Procedures http://energy.gov/articles/proposed-change-energy-departments-lng-export-decision-making-procedures

[38] A Proposed Change to the Energy Department's LNG Export Decision-Making Procedures http://energy.gov/articles/proposed-change-energy-departments-lng-export-decision-making-procedures

countries, with a total export capacity of 10.52 Bcf/day. Before this change was implemented, the DOE had 23 outstanding applications requesting approval to export LNG from the U.S. with a total cumulative export capacity of up to 35.86 Bcf/day, if all are approved. [39] However, it is likely that the DOE will cap the total amount exported to 20 Bcf/day.[40]

Table 1: Non-FTA Approved U.S. LNG Export Projects[41]

Non-FTA Approved U.S. LNG Export Projects	Export Capacity (Bcf/day)	Target Export Year
1. Cheniere Energy, Sabine Pass	2.2	2016
2. ConocoPhillips, Freeport LNG	1.4	2018
3. Energy Transfer Partners, Lake Charles	2.0	2019
4. Dominion, Cove Point LNG	0.77	2017
5. Veresen, Jordan Cove Energy Project	0.8	2018
6. Cameron LNG	1.7	2018
7. Freeport LNG Expansion and FLNG	0.4	2018
8. LNG Development Co. LLC (Oregan LNG)	1.25	2019
Total	**10.52**	

US Department of Energy LNG Report

The DOE undertook an economic study in 2012 to provid a comprehensive assessment on the impacts of LNG exports from the U.S., with particular focus on domestic gas prices and economic impacts. The report concluded that LNG exports would provide a net economic benefit to the U.S. economy and that the benefits would outweigh the net costs.

In terms of impact on domestic gas prices, the report concluded that if LNG exports reach 6 Bcf/day by 2015 then domestic gas prices could rise up by $0.33 US/Mcf. Eventually, after five years of LNG exports, when 12 Bcf/d are forecast to be exported annually, domestic gas prices are estimated to rise between $0.22 and $1.11 US/Mcf. The forecasted maximum price increase of $1.11 US/Mcf assumes that LNG projects reach the maximum export capacity of 12 Bcf/day.

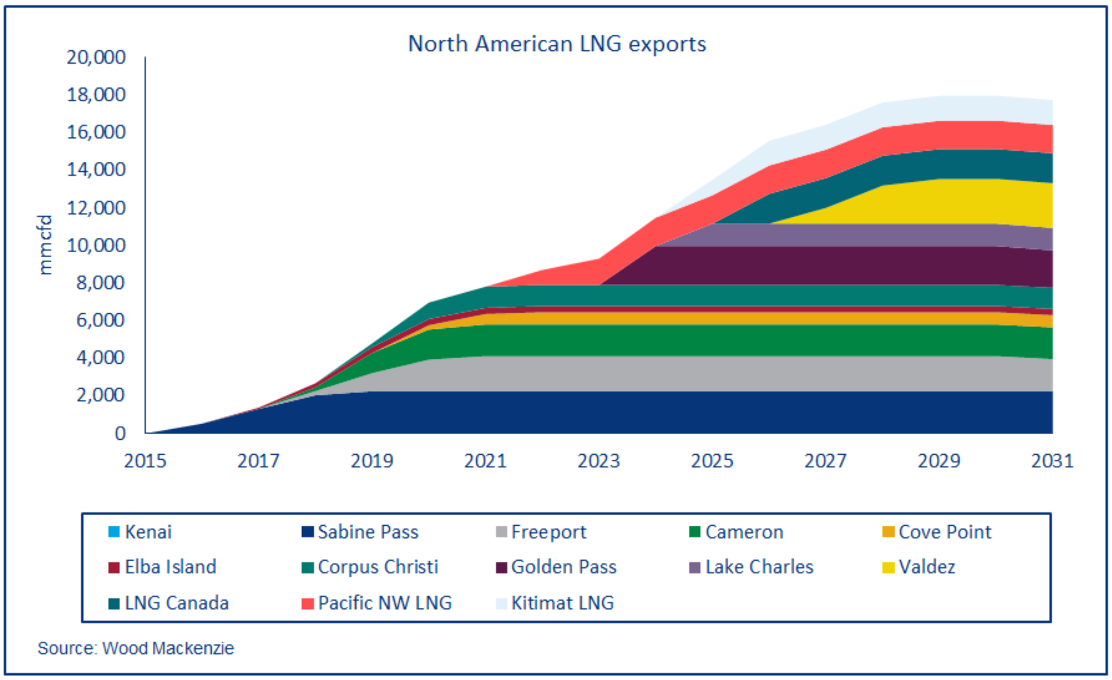
In all analysed cases, the DOE report concluded that the net benefits to the U.S. would increase as LNG exports would increase the overall economic output such as employment, business revenues, tax revenues, etc. Although the DOE report indicated that more LNG exports would be better for the economy, the probability that all proposed projects will be approved remains low.

[39] http://www.energy.gov/sites/prod/files/2014/03/f13/Summary%20of%20LNG%20Export%20Applications.pdf
[40] DOE's New Procedure for Approving LNG Export Permits: A More Sensible Approach http://www.brookings.edu/research/articles/2014/06/10-doe-approving-lng-export-goldwyn-hendrix
[41] U.S. Department of Energy

The DOE plans to update this study by looking at the economic impact of an increased range of LNG exports (12-20 Bcf/d) and other effects that LNG exports might have on the U.S natural gas market in the near future.[42] However, there is currently no formal timeline for the release of this report.

Figure 17 provides a forecast of gas demand for LNG exports from North America for various regions. U.S. LNG exports are expected to increase substantially after 2017, eventually reaching 13.5 Bcf/d by 2030.[43] For Western Canada, Wood Mackenzie expects LNG exports to begin in 2022 and to ramp up to 4.4 Bcf/d by 2030.

Figure 17: North American LNG Exports[44]



3.6 *NATURAL GAS FOR TRANSPORTATION*

Another source of gas demand growth will come from the development of the NGT market as North American natural gas prices are expected to remain at a significant discount to gasoline and diesel prices. Conversion from tradition fuels such as diesel and gasoline in natural gas vehicles (NGV) and marine vessels to either compressed natural gas or liquefied natural gas will likely contribute to higher gas demand in the future. The largest segment of demand in the NGT industry is demand is the NGV market.

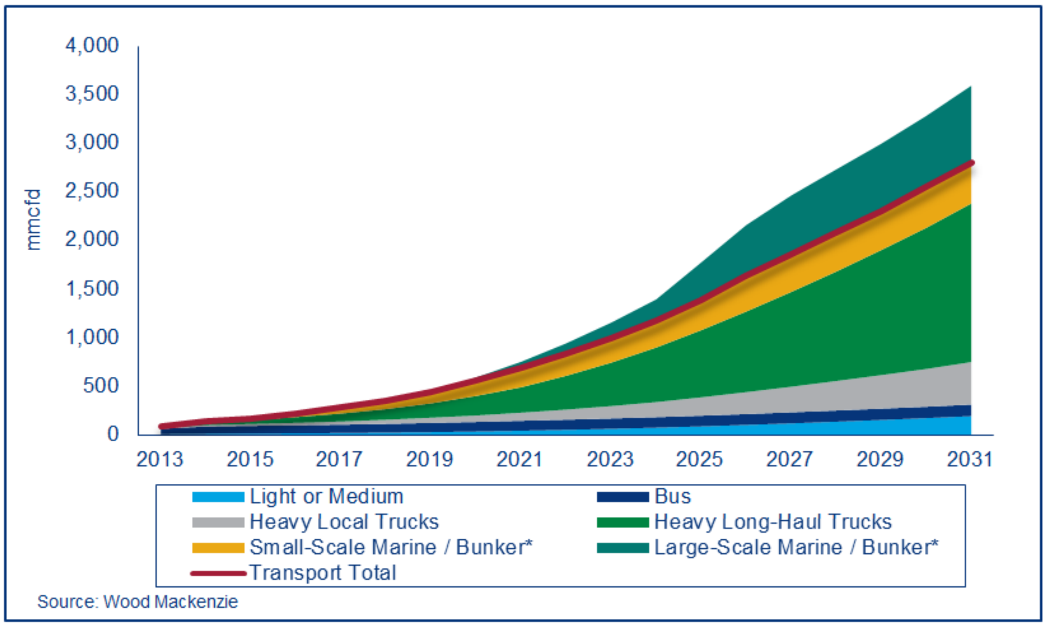
[42] DOE Request for an Update of EIA's January 2012 Study of Liquefied Natural Gas Export Scenarios http://energy.gov/sites/prod/files/2014/05/f16/Request%20for%20Updated%20EIA%20Study.pdf
[43] Wood Mackenzie, North America Natural Gas Long Term Outlook May 2014
[44] Wood Mackenzie, North America Natural Gas Long Term View, May 2014

Natural Gas Transportation

From the period 2008 to 2010, natural gas demand for NGVs rose at a rate of about 13% per year as natural gas prices continued to be more competitive than traditional fuels, such as diesel and gasoline.

According to the forecast for NGT gas demand presented in the Figure 18 below, U.S. gas demand is expected to grow from about 0.1 Bcf/d in 2013 to about 2.5 Bcf/d by 2030. While significant for the NGT market, overall NGT demand is expected to represent only about 2% of total U.S. gas demand by 2030.

Figure 18: U.S. NGT Natural Gas Demand[45]



FEI and the NGT Market in B.C.

FEI has also experienced increased natural gas demand related to the NGT market through increased adoption of natural gas vehicles. This increase in demand in the NGT sector is primarily due to FEI's ability to issue financial incentives to qualifying customers to purchase CNG and LNG vehicles as permitted under the province's Greenhouse Gas Reductions (Clean Energy) Regulation (GGRR). To date, FEI has conducted five rounds of financial incentive funding to a number of CNG and LNG customers. To date, FEI has received customer commitments which have resulted in a total addition of 390 heavy duty vehicles and 5 marine vessels. Of the 395 natural gas vehicle commitments received to date, about 130 heavy duty vehicles will come into operation in 2015 and the 5 marine vessels are expected to be in operation in 2016.

[45] Wood Mackenzie, North America Natural Gas Long Term View, May 2014

In terms of the environmental benefits impact, the 395 total natural gas vehicles (which include the 5 marine vessels), once all are in operation, will result in an overall reduction of about 38,000 metric tonnes of carbon dioxide equivalent (CO2e) per year. This will be the equivalent of removing about 8,000 medium size passenger vehicles from the road per year.

BC Ferries has committed to acquiring 3 dual-fuel marine vessels for delivery Q4 2016 through Q2 2017 and Seaspan has committed to acquiring 2 dual-fuel marine vessels, which are expected to be in operation in Q4 2016. The adoption of natural gas, particularly for high consumption sectors such as coastal marine operations, will also allow the B.C. government to achieve its goals of reducing GHG emissions by converting more carbon intensive fuels, such as diesel, to relatively more clean burning fuels, such as natural gas.

Although NGT demand (CNG and LNG) is expected to be a relatively small portion of FEI's overall gas supply portfolio in the short term, growth in NGT demand is expected to increase over the next number of years. NGT demand is expected to increase due to the following reasons: certainty regarding LNG supply availability and stable LNG delivery pricing has given customers a basis to make the economic business cases of switching to natural gas, customer awareness/education on the economic and environmental benefits of switching to natural gas and the availability of fueling infrastructure is built out and accessibility to fueling locations is expanded along strategic corridors.

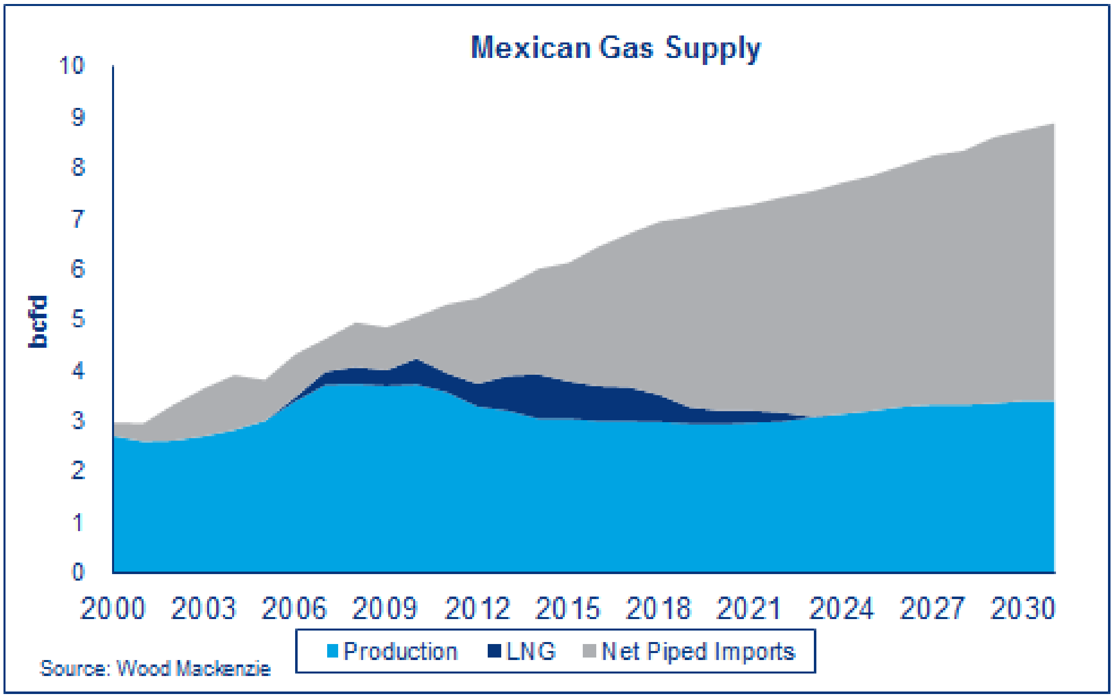
3.7 *U.S. EXPORT DEMAND INTO MEXICO.*

As Mexico continues its efforts to phase out oil use for power generation, gas-fired capacity is expected to increase. By 2030, total demand for natural gas in Mexico is forecast to reach 8.7 Bcf/d from 5.7 Bcf/d in 2013, with gas demand growth largely attributed to power generation.

Although the Mexican government has indicated its plan to use the shale (i.e. the Burgos basin) and deep water gas production (i.e. the Lakach basin) projects as alternatives to satisfy upcoming demand, limited production improvement is expected in the short-term from these supply sources given the capital-intensive nature of these projects. As Mexico faces challenges in meeting the growing gas demand through domestic production, it is turning to importing gas from the U.S. as a solution.

Figure 19 illustrates the Mexican natural gas demand up to 2030 and the various supply sources to satisfy the growing demand. By 2030, over 60% of Mexican gas demand is expected to be met by pipeline imports.

Figure 19: Mexico Natural Gas Demand [46]



In order for U.S. pipeline imports to become a secure source of supply for Mexico, various pipeline projects have been proposed to resolve bottlenecks that limit import capacity at the U.S./Mexico border, as well as to reallocate domestic production to reduce the use of fuel oil. Current new pipeline projects, including the Los Ramones, Chihuahua, and the Noroeste projects, will increase total import capacity by pipeline up to 8.3 Bcf/d, enough to satisfy domestic consumption by 2030.

3.8 *DEMAND SUMMARY*

The expectation of a continuing relatively low price environment is providing an incentive for the market to develop and expand uses of natural gas. The promotion of natural gas by local and federal governments also favourably positions its use in the future to meet environmental and energy self-sufficiency objectives. In the short term, increased demand for natural gas is expected from industrial development, a greater dispatch of natural gas for power generation, and demand from oil sands production in Alberta.

Over the longer term, demand for gas is expected to increase primarily due to LNG exports, industrial demand, gas-fired power generation, and U.S. export demand into Mexico. To a lesser degree, demand will also increase due to the expansion of the NGT industry. This will serve to increase gas prices above current levels and subsequently increase natural gas supply brought to market. As Goldman Sachs stated: “we believe that these structural changes in

[46] Wood Mackenzie, U.S. Gas Goes South: A Review of Mexico's Infrastructure, July 2013

demand will ultimately move the market away from pricing fuel substitution and towards pricing marginal cost of production, as natural gas drilling and, ultimately, supply, will need to rise more significantly to accommodate the changes in U.S. natural gas demand."[47]

[47] Goldman Sachs, Natural Gas Weekly, September 11, 2013

4. NATURAL GAS STORAGE BALANCES

Natural gas storage balances represent the amount of natural gas storage inventory levels, which fluctuate up and down throughout the year as gas is injected into storage facilities during the lower-demand summer months and withdrawn from storage to help meet demand during the winter months. In the short term, storage balance levels are the result of the outcome of various supply and demand drivers in the gas marketplace and therefore provide a good snapshot of current market conditions. As a consequence, storage balances influence market gas prices, particularly in the near term.

Storage balances at the end of winter 2013/14 were at their lowest levels in over a decade due to one of the coldest winters experienced in North America in decades. This extreme winter weather due to the polar vortex effect resulted in seven out of the ten highest natural gas demand days on record for the U.S. in January 2014.[48]

However, with strong gas production and relatively weak gas air-conditioning demand due to mild weather throughout summer 2014, gas storage inventory levels have recovered significantly at the end of summer 2014. Figure 20 shows the cooling degree days[49] (CDDs) for summer 2014 compared to the previous summer and the 5-year average. As illustrated, beginning in July, summer 2014 has been noticeably cooler than summer 2013 and the 5-year average in most cases.

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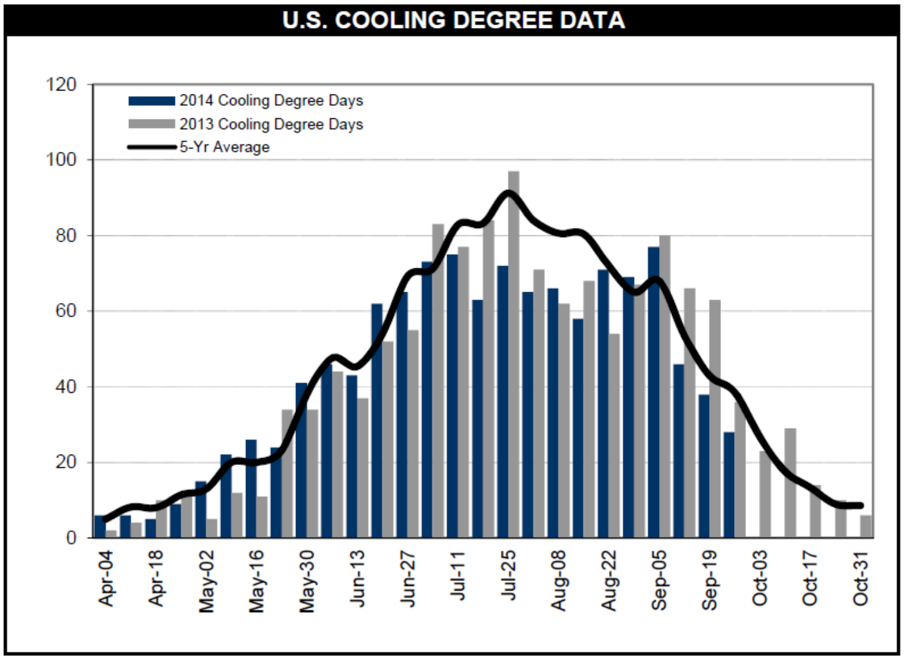
48 http://www.marketwatch.com/story/polar-vortex-brought-record-natural-gas-demand-2014-02-03?link=MW_home_latest_news

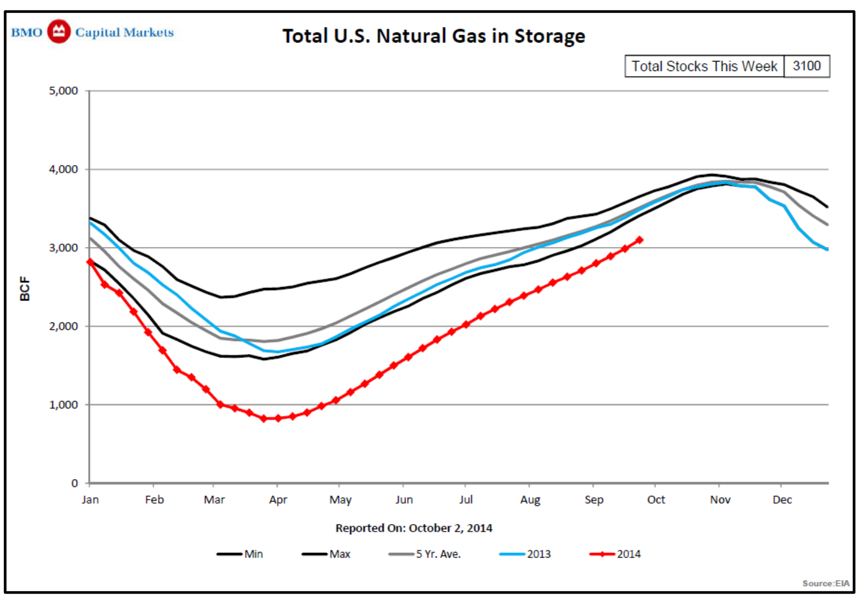
49 EIA Glossary – Cooling Degree Days (CDD): A measure of how warm a location is over a period of time relative to a base temperature, most commonly specified as 65 degrees Fahrenheit. The measure is computed for each day by subtracting the base temperature (65 degrees) from the average of the day's high and low temperatures, with negative values set equal to zero. Each day's cooling degree days are summed to create a cooling degree day measure for a specified reference period. Cooling degree days are used in energy analysis as an indicator of air conditioning energy requirements or use.

Figure 20: U.S. Cooling Degree Days[50]



As illustrated in Figure 21, U.S. working gas in storage was 3,100 Bcf for the week ending September 26, 2014, which is only 10.7% below last year's level of 3,473 Bcf and 11.4% below the 5-year average of 3,499 Bcf.

Figure 21: U.S. Natural Gas Storage Inventory[51]



[50] NBC, weekly update – October 2, 2014
[51] BMO – U.S. Natural Gas Storage Charts – October 2, 2014

Larger-than-normal storage injections throughout summer 2014 have significantly narrowed the year-to-year storage deficit to only 373 Bcf for the week ending September 26, 2014, compared to a year-to-year deficit of 797 Bcf for the week ending May 2, 2014. The EIA expects storage inventory levels to reach 3,500 Bcf by November 1, 2014 and could continue to build as winter 2014/15 starts. Higher storage levels, all else equal, could help pressure market gas prices lower.

5. NATURAL GAS PRICES

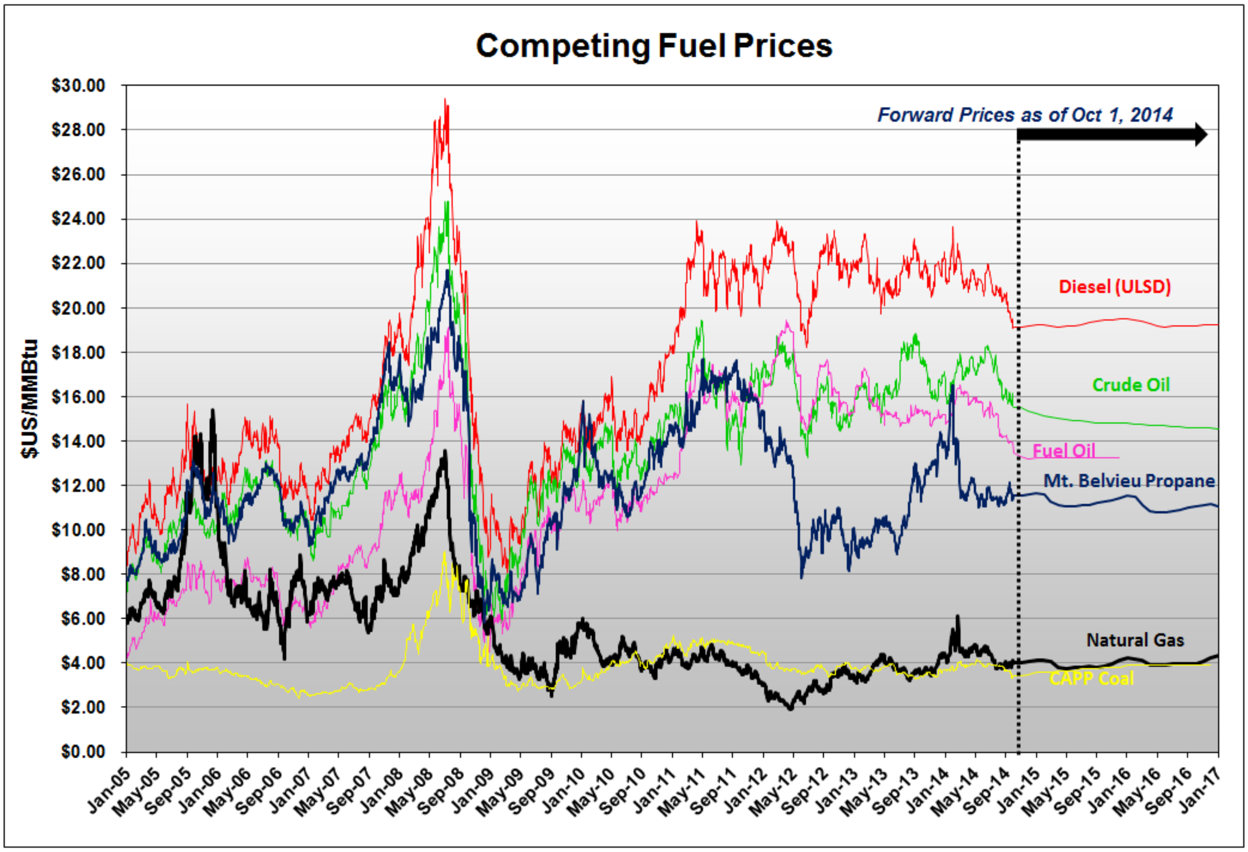
With the abundance of shale gas supply in recent years, natural gas prices have come down from the levels seen prior to 2009 where prices typically remained above $6 US/MMBtu and higher. Due to the exceptionally warm 2011/12 winter, natural gas prices reached their lowest levels in a decade in mid-2012, but have rebounded above $4 US/MMBtu after a cold 2013/14 winter. With larger-than-normal storage injections due to strong gas production and mild weather throughout most of summer 2014, natural gas prices have hovered below the $4 US/MMBtu level near the end of summer 2014.

Furthermore, natural gas prices continue to remain disconnected from other competing fuels, such as heating and fuel oil, which are derived from crude oil and can be used as substitutes for natural gas in certain applications, such as space heating and power generation. Crude oil prices are highly influenced by global supply and demand factors and geopolitical tensions, whereas North American natural gas prices have been relatively isolated from such factors and more dependent upon regional supply and demand dynamics.

Currently, Central Appalachian (CAPP) coal prices are also near the $4.00 US/MMBtu level. The fuel switching demand mostly derives from power generators that can deploy natural gas generation in lieu of coal depending on the relative price differences between the two fuels. When natural gas prices are below the CAPP coal prices, demand for natural gas increases due to switching from coal, which drives gas prices higher, and vice versa. So CAPP coal prices act as a soft cap and floor for natural gas prices, keeping them somewhat rangebound until a significant event, such as weather, moves them higher or lower.

Figure 22 shows prices (historical prompt month and futures) for various competing fuels with natural gas as of October 1, 2014. At the current time, forward natural gas prices are near the $4 US/MMBtu level. This can change quickly, however, in response to weather and supply and demand balances.

Figure 22: Competing Fuel Prices, North America[52]



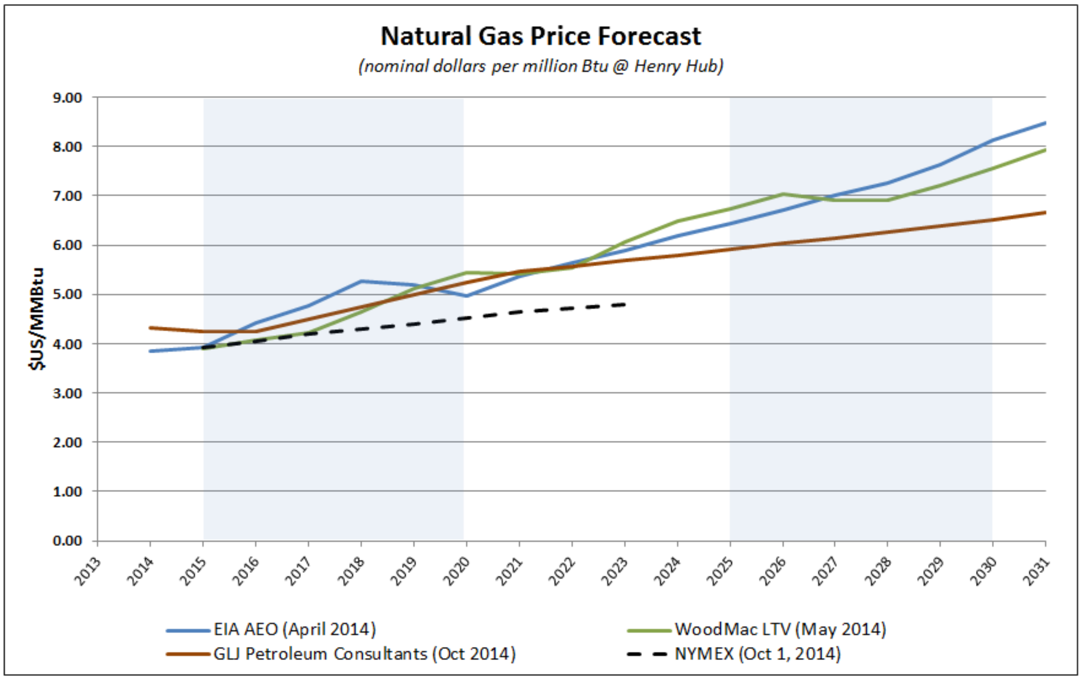
5.1 *LONG RANGE PRICE FORECASTS*

Figure 23 shows various recent long term price forecasts for natural gas based on the Henry Hub market in nominal dollars, compared to the current NYMEX forward curve in October 2014. All forecasts show gas prices over the long run follow an upward trend due to a tighter balancing of supply and demand. Natural gas demand is expected to increase in the long run and higher prices are required to bring incremental supply online to satisfy this demand due to declining low-cost supply and incentive required to shift producers away from oil drilling.

This forecast shows that by 2020, gas prices could be in the range of about $5.00 US/MMBtu and $5.50 US/MMBtu. By 2025, analysts forecast that gas prices could be in the range of about $6.00 US/MMBtu and $7.00 US/MMBtu.

52 U.S. Energy Information Administration & CME Group, April 7, 2014

Figure 23: Natural Gas Price Forecasts



5.2 *PRICE VOLATILITY*

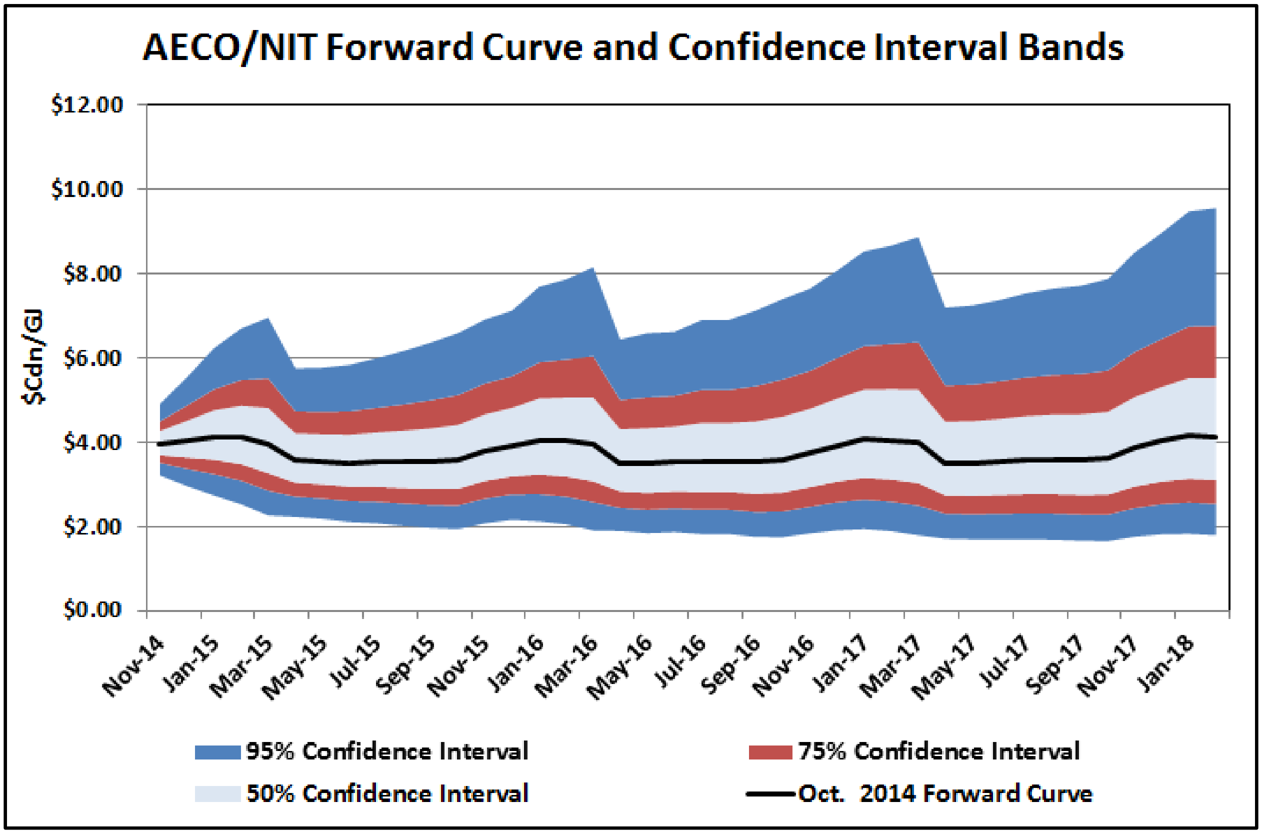
In addition to looking at market prices, market price volatility also provides an indication of potential prices and price movements in the future. Price volatility can be measured in one of two ways: using either observed or implied volatility.[53]

Figure 24 below shows the forward AECO/NIT price range that is derived from the implied volatility as of October 1, 2014. The figure illustrates three confidence intervals of 50%, 75%, and 95% to provide different envelopes of potential future price movements. For example, the figure shows that for January 2018:

- The forward curve is trading at about $4.16 Cdn/GJ;
- There is a 95% probability that prices will range between $1.79 Cdn/GJ and $9.56 Cdn/GJ, for a range of $7.76 Cdn/GJ;
- There is a 75% probability that prices will range between $2.53 Cdn/GJ and $6.77 Cdn/GJ, for a range of $4.23 Cdn/GJ; and
- There is a 50% probability that prices will range between $3.11 Cdn/GJ and $5.52 Cdn/GJ, for a range of $2.42 Cdn/GJ.

[53] Observed volatility uses historical settled price movements over a defined period of time (such as 15, 20, 30, etc. trading days) and applies these observed changes to futures prices to model a forward curve. Implied volatility is the volatility of the price that is assumed by the market based on an option pricing model, such as Black-Scholes. This can be used to provide a probable range for natural gas prices in the future.

Figure 24: AECO/NIT Forward Curve and Confidence Interval Price Bands[54]

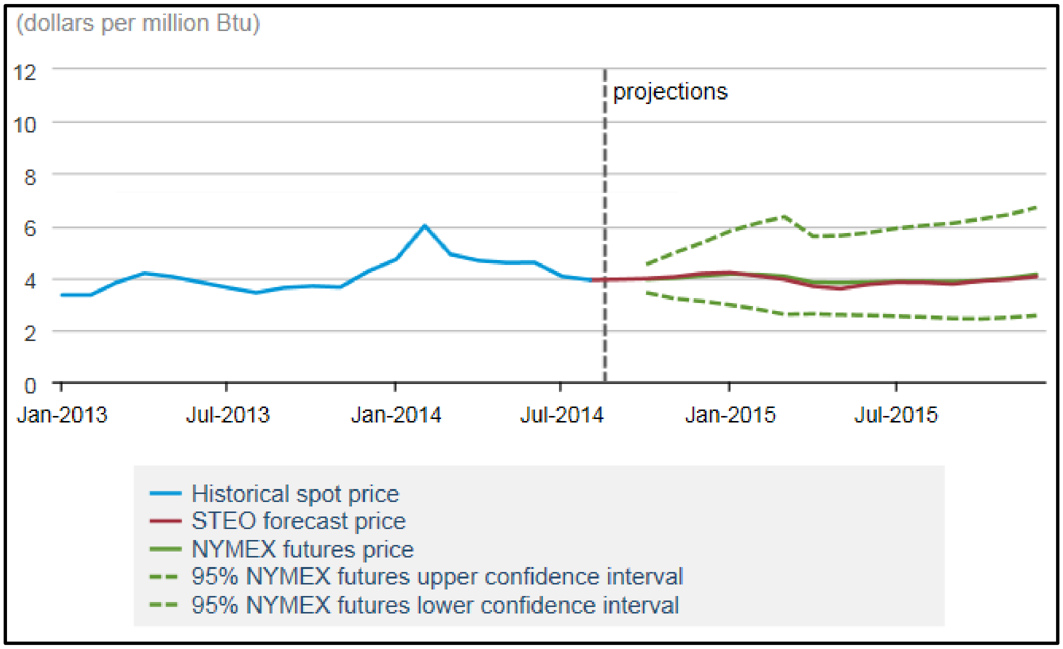


The volatility analysis provided in the Figure 24 highlights that there is more potential for upside price movements than there is potential for downside price movements. This is consistent with the market's view that current gas prices are below or near the production costs for many of the shale gas plays.

Figure 25 displays the EIA's Henry Hub natural gas price forecast and current NYMEX futures price curve as of September 2014. It also includes a 95% confidence interval forecast that provides a range of possible natural gas prices in the future. In other words, the EIA expects the January 2015 gas price to settle in between a range of $2.95 US/MMBtu and $5.80 US/MMBtu with a 95% probability.

[54] CME Group, One Exchange Corp., Goldman Sachs Group, March 31, 2014

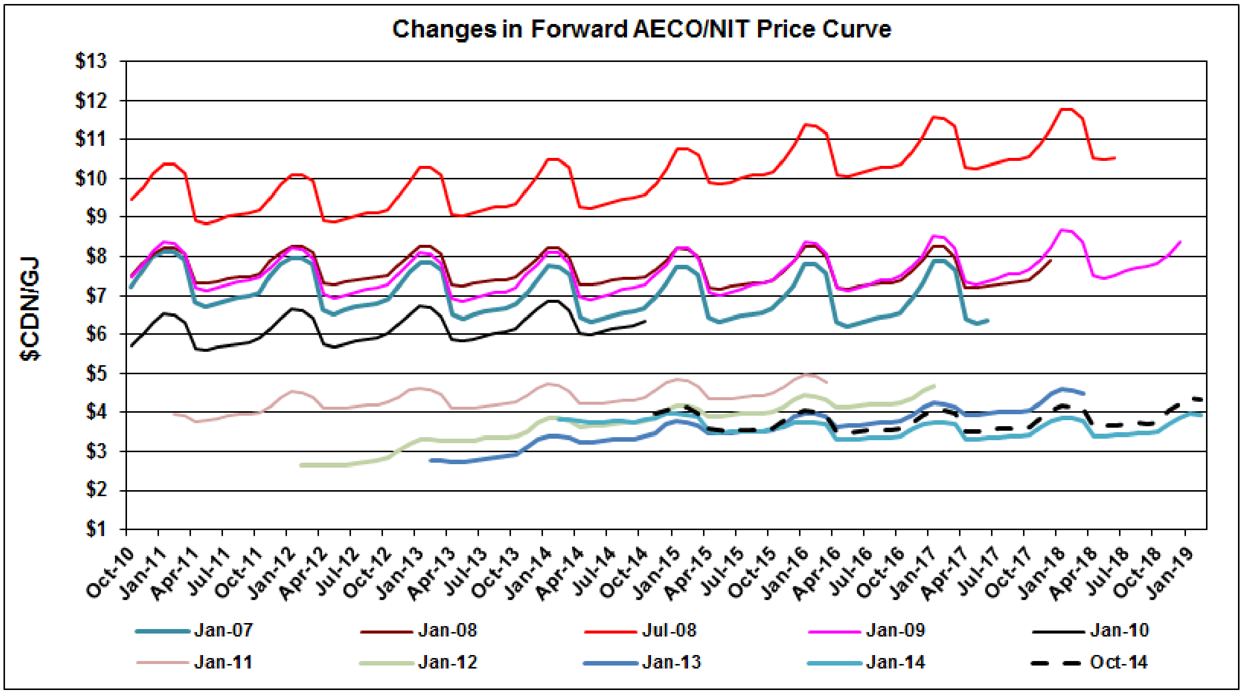
Figure 25: Henry Hub Natural Gas Price Forecast[55]



Another way of looking at price volatility is to observe changes to the forward price curve over a period of time. As Figure 26 illustrates, the AECO/NIT forward price curve has changed dramatically over the past number of years.

[55] U.S. EIA, Short-Term Energy Outlook, September 2014

Figure 26: Changes in AECO/NIT Forward Curve[56]



The wide range of forward price curves helps to highlight key points about current natural gas prices. First, natural gas forward prices continue to remain near the lower end of recent historical ranges. Second, given the break-even costs of natural gas production, it is unlikely that natural gas prices will decrease significantly from current levels for a significant period of time. As demand for natural gas increases and there is more certainty regarding industrial and LNG exports projects, it is likely that forward prices will increase as reflected in the price forecasts.

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[56] CME Group, One Exchange Corp., October 2014

6. SUMMARY

The North American natural gas marketplace has undergone significant changes in the last few years. The development of unconventional gas, in particular shale gas, has transformed the market from one of declining supply and requiring imports to an abundance of supply resulting in relatively low commodity prices. This has led to increased demand for natural gas, particularly with respect to industrial use and power generation, and created opportunities for the development of LNG exports and NGT markets in North America as well as FEI's region.

In the near term, strong gas production and mild weather throughout summer 2014 and coal switchability for power generation have limited prices to near the $4/MMBtu level. Storage levels have somewhat recovered after the cold winter 2013/14 prior to winter 2014/15. While a cold winter 2014/15 could boost gas prices, a warm winter will likely lower gas prices, at least in the short term.

Over the longer term, future natural gas prices are expected to rise with increasing and new sources of demand, though they are not expected to increase to the peaks seen in the recent past. This should provide both favourable returns for gas producers and reasonable costs for end users and consumers so that natural gas continues to grow in its role as a primary energy source in North America.

Appendix B

REGIONAL MARKET AND REGULATORY OVERVIEW

1. INTRODUCTION

Significant changes are occurring in the natural gas marketplace in western Canada. These changes will likely impact traditional supply and demand dynamics and regional gas flows as well as regional market price relationships. The significant supply potential in northeast BC has prompted the development of infrastructure initiatives to provide greater access to existing and new markets. With declining gas supplies in Alberta and increasing demand from industrial, power generation and oil sands demand, TransCanada is expanding into northeast BC to access the significant new production basins that are being developed there. Numerous LNG export projects have also been announced for the west coast of BC. Other projects have been proposed in the US PNW to move more gas to the growing I-5 market.

Within the context of this background, this Appendix provides an update of key developments that are influencing the market dynamics in BC, Alberta, and the US PNW. The most important areas of interest include:

- the importance of northeast BC supply for markets in BC;
- the development of potential LNG export projects;
- developments affecting TransCanada's NGTL system, including extensions into northeast BC;
- facilities developments affecting Spectra's system in BC; and
- developments affecting pipeline capacity in the US PNW.

2. THE IMPORTANCE OF NORTHEAST BC SUPPLY

Improvements in production technologies that have unlocked the potential of shale and tight gas resources have transformed the North American natural gas supply picture. In British Columbia, the natural gas potential is second only to the Marcellus that is being developed in the northeast region of United States. A joint study by the National Energy Board, BC's Ministry of Natural Gas Development, the BC Oil and Gas Commission, and the Alberta Energy Regulator that was published in November 2013, estimated that 1,965 trillion cubic feet[1] of gas-in-place is available in BC, which represents a significant increase over previous estimates. The Montney formation in BC alone represents 449 trillion cubic feet[2] of potential natural gas. As a result of the size of this resource, the production of natural gas from basins located in northeast BC has the potential to grow significantly in the coming years. It is able to support existing markets in BC, as well as support LNG export projects, to offset declining Alberta production, to meet growing industrial demand in Alberta, including from oil sands developments, and the emergence of new industrial baseload markets in BC and the PNW.

The prospect of the development of new markets for production is welcome news for producers active in the Western Canadian Sedimentary Basin (WSCB). The traditional Canadian and US market for natural gas produced in the WCSB has declined steadily over the past few years. This decline is driven primarily by the development of shale gas basins, in particular the Marcellus shale gas play, that are located much closer to key consuming markets in eastern North America. It is also driven by low gas commodity prices that reduce supply that is economically recoverable from conventional and other sources. While increased industrial, power generation, and oil sands demand will help to offset reduced demand from traditional markets significant new markets are required in order to fully develop the potential of the WCSB, including the new supply basins located in northeast BC.

FEI is required to serve several major regional demand centres in BC that are largely isolated from each other by considerable distances and spread across a large, varied geographical footprint. In order to serve customers across this diverse geography and to balance daily system loads, requires interconnection with third party pipelines and access to a flexible mix of supply, storage, and transportation resources.

As a matter of additional complexity, BC's geography, location relative to supply basins, and its winter seasonal market, has limited the infrastructure available that connects the BC marketplace to sources of supply. As a consequence, the BC market is extremely reliant on supply originating in production basins located in northeast BC. Over 80% of FEI's current supply is sourced in BC and transported to FEI's service area via Spectra's T-North and T-

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[1] BC Ministry of Natural Gas Development, Newsroom Economy, Government Operations Wednesday, November 6, 2013.

[2] Energy Briefing Note, The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta, NEB, BCOGC, Alberta Energy Regulator, Ministry of Natural Gas Development, November 2013.

South pipeline systems. This reliance on northeast BC supply is unlikely to change significantly in the short to medium term given that only limited pipeline capacity exists to connect supply from Alberta and for redelivery from market area storage located in the US PNW.

In response to the combination of the increase in demand in Alberta and the decline in Alberta production, pipeline connectivity from supply basins located in northeast BC to Alberta has increased since 2010. The majority of recent pipeline expansions to the AECO/NIT market, such as the Groundbirch and Horn River Mainline pipelines by NGTL, now provide BC producers with the option to flow increased supply directly to AECO/NIT marketplace, bypassing Spectra's T-North system. Future facilities additions in northeast BC contemplated by TransCanada for its NGTL system will likely accelerate this trend.

Notwithstanding this development, it is possible for gas produced in BC to flow onto the NGTL system into Alberta and then flow back into BC. The infrastructure connections with Spectra's T-North system at Groundbirch, Gordondale and Horn River could permit flow from NGTL onto Spectra's system but requires the addition of facilities on the NGTL system. Such additions would result in increased costs to access this gas since shippers would have to pay the AECO/NIT price plus both the NGTL delivery toll as well as the Spectra T-North toll to deliver gas to Station 2. T-North tolls may also increase as a result of facilities additions that would be required to increase capacity in order to accommodate any significant increase in flows on T-North to Station 2 from the Groundbirch/Gordondale area on the NGTL system.

3. PRODUCERS ACTIVE IN NORTHEAST BC

Over the past several years, with the expansion of shale gas production, commodity prices for natural gas have been at their lowest in a considerable period of time. Western Canadian natural gas producers have been hit the hardest, as not only have prices periodically fallen close to $2.00/GJ, Canadian exports to the US have also dropped dramatically. Natural gas produced from the Marcellus shale and the Rockies continue to cut into demand from Western Canada. Production costs in northeast BC make the development of new supply outside of the liquids rich Montney basin uneconomic given recent commodity prices. This has resulted in very little activity in other basins in the region, like Horn River, even though it has a considerable reserve potential. Other areas in northeast BC facing this challenge includes the Liard basin, as it has gas that is only slightly richer than Horn River, and Pine River as it has generally dry gas with a high acid content, which means higher commodity prices are required to develop their potential.

Facing these difficult challenges, Western Canadian natural gas producers have been forced to reconsider their strategies in order to survive in this low price environment.[3] The following subsection discusses how natural gas producers have attempted to develop new strategies to respond to a low price environment.

3.1 *PRODUCERS ARE RECONSIDERING BUSINESS STRATEGIES*

Facing pressure to focus on increasing returns on capital invested, many producing companies decided to either suspend or divest gas assets in northeast BC in 2013 and 2014. Earlier this year, Suncor for example, announced a suspension of plans to develop its shale gas property in BC's Montney basin. Suncor spokeswoman Sneh Seetal noted that "this was nothing to do with the quality of the resource but a question of timing."[4] Suncor is reluctant to increase production until there was, as Seetal added, "a change in market supply and demand fundamentals."[5]

Talisman, one of the largest gas producers in Canada, is another company that had to realign its initiatives after it posted a $1 billion quarterly loss in the fourth quarter of 2013. Faced with disgruntled shareholders Talisman put up $2 billion of assets for sale. Soon after this news was released, it agreed to sell off 75% of its Montney property for $1.5 billion, to Malaysia's Petronas[6].

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[3] **The Energy Frontier: Reinventing Canadian natural gas companies -** http://business.financialpost.com/2014/01/24/the-energy-frontier-reinventing-canadian-natural-gas-companies/?__lsa=6299-e74a

[4] **Suncor retreats from LNG rush, suspends BC shale gas work -** http://business.financialpost.com/2014/01/29/suncor-retreats-from-lng-rush-suspends-b-c-shale-gas-work/

[5] **Suncor retreats from LNG rush, suspends BC shale gas work -** http://business.financialpost.com/2014/01/29/suncor-retreats-from-lng-rush-suspends-b-c-shale-gas-work/

[6] **Talisman Sells Montney to Petronas for $1.4 Billion** - http://www.bloomberg.com/news/2013-11-08/talisman-sells-montney-assets-to-progress-for-1-4-billion.html

Finally, Devon Energy in December 2013 put most of its Canadian gas assets up for sale, as it grew impatient with years of low gas prices and saw little prospect for a turnaround. The president of Devon Canada, Christopher Seasons expressed his thoughts over the depressed gas prices in an interview saying "when we look out a few years, we don't see any major catalyst to move the price of natural gas substantially, and for us to be competitive that is what we need to see"[7]. As a result in February 2014, Devon Energy sold its natural gas properties, surprisingly to Canadian Natural Resource Limited (CNRL), who in March 2013, was also trying to unload its assets in the Montney region but was unsuccessful.[8] One of CNRL's reasons for acquiring much of Devon Energy's land in northeast BC was that the property is located in a liquids-rich natural gas weighted area. This leads into the next strategy that natural gas producers have taken.

Natural gas liquids, or NGLs, are hydrocarbons such as ethane, propane, butanes that are often found alongside dry natural gas. As the United States Energy Information Administration (EIA) stated, natural gas producers are "increasingly targeting liquids-rich parts of supply basins due to higher crude prices, which influence the value of NGLs."[9] Faced with low natural gas prices and stalled dry gas demand, Western Canadian gas producers have been focusing more on liquid rich natural gas and oil, which the North Montney shale formation has.

Encana exemplifies this, as it faced difficult times with company share price dropping, it hired a new CEO, Doug Suttles to transform and restructure the company. In December 2013, the Chief Executive Officer of Encana, Doug Suttles, announced the companies 'less is more strategy'[10] which meant selling off its dry natural gas assets (some of which in Canada) and focus on oil and liquids rich plays. The Montney shale formation was going to be an important asset to Encana as their website states, their focus in 2014 will "center on accelerating the development of the oil and liquids-rich areas of this [Montney] play."[11] Encana began to cut into its assets by getting out of dozens of plays in Alberta, Nova Scotia and in the United States.[12]

Apache is another example of how the focus is shifting to liquid oil and gas production. In late March, the Financial Post reported that Apache was trying to sell its dry natural gas assets in Western BC and Alberta for $374 million.[13] Similar to Encana, once Apache was able to sell the land to an undisclosed buyer, the CEO released a statement calling the transaction a part "of

[7] **Devon Energy Corp to put Canadian natural gas assets up for sale as low prices bite** http://business.financialpost.com/2013/12/06/devon-energy-corp-to-put-canadian-natural-gas-assets-up-for-sale-as-low-prices-bite/?__lsa=bbad-b0f7

[8] **Canadian Natural Resources calls off auction of BC Montney land holdings** http://www.vancouversun.com/technology/Canadian+Natural+Resources+calls+auction+Montney+shale+holdings+citing+insufficient+bids/9370044/story.html

[9] **What are natural gas liquids and how are they used?** http://www.eia.gov/todayinenergy/detail.cfm?id=5930

[10] **Encana finding its focus:** http://www2.canada.com/calgaryherald/news/business/story.html?id=601d8862-08df-4958-bdb4-2ac4a50f4df0&p=1

[11] **Encana** - https://www.encana.com/operations/montney.html

[12] **Encana finding its focus:** http://www2.canada.com/calgaryherald/news/business/story.html?id=601d8862-08df-4958-bdb4-2ac4a50f4df0&p=1

[13] **Apache to sell western Canada assets in liquids push** - http://business.financialpost.com/2014/03/31/apache-to-sell-western-canada-assets-in-liquids-push/?__lsa=6299-e74a

Apache's portfolio rebalancing, which was undertaken last year to enable Apache to focus on growing liquids production..."[14]

Although Horn River and the Montney have huge natural gas resources, the low commodity prices over the past several years caused gas producers in Western Canada to change their strategies and to reconsider the development of production in northeast BC. The effect of this response is that a number of large producers traditionally active in northeast BC, such as Apache, Talisman, Imperial Oil, and Suncor, are reducing their presence in the market.

While higher commodity prices that developed this past winter offers some encouragement to producers to resume or embark on new development activities in northeast BC, higher prices need to remain for some time before the retrenching process that was kicked off last year ends.

[14] **Apache agrees to sell oil and gas assets in BC and Alberta's Deep Basin for $374 million** http://www.biv.com/article/20140331/BIV0108/140339994/-1/BIV/apache-agrees-to-sell-oil-and-gas-assets-in-bc-and-albertas-deep

4. BC LNG EXPORT PROJECTS

The last few years has seen the announcement of a number of LNG export projects that propose the construction of liquefaction terminals on BC's west coast, as well as large diameter pipelines to transport natural gas from new production basins in northeast BC to the liquefaction terminals. The main driver of these projects is the desire to take advantage of the differential between natural gas prices in Asia (higher) and North America (lower). The Asia markets are also seeking to diversify their sources of supply and are attracted by the political stability and mature market structure for accessing natural gas that Canada offers.

4.1 *PROPOSED BC LNG EXPORT PROJECTS*

4.1.1 Overview of Projects

Up to 15 LNG export projects have been proposed for locations on the west coast of BC and are set out in Table 1. Of these, 13 are located in the Kitimat, Prince Rupert and Kitsault region, on the northern coast of BC, and two are located outside of this area near Squamish and Campbell River. The 13 projects considered for the north coast of BC, with the exception of the BC LNG Export Co-Op, will all require substantial new pipeline infrastructure. Four of these projects have announced plans to construct new large diameter pipelines to bring supply from the new production basins in northeast BC. Please refer to Figure 1 for a map showing the location of these potential LNG export facilities and their planned pipeline routes.

A smaller scale LNG export proposal has also been announced for location at a site near Squamish that plans on accessing supply via the FEI systems.

Table 1: Proposed LNG projects on the West Coast of BC

Proposed LNG Export Projects in B.C.						
Project	**Partners**	**Min Capacity (Bcf/d)**	**Max Capacity (Bcf/d)**	**Final Investment Decision ****	**Export Date**	**Pipeline**
1. Douglas Channel LNG*	BC LNG Export Co-op, Haisla Nation, LNG Partners	0.9	0.11	see note below	see note below	PNG's existing line and PNG Looping Project
2. Triton LNG *	AltaGas, Idemitsu (Japan)	0.28	0.3	2015	2017	PNG Looping Project
3. Kitimat LNG*	Chevron, Apache	0.6	1.3	not available	2016	Pacific Trail Pipelines
4. Pacific Northwest LNG*	Petronas, Japex, Petroleum Brunei, Indian Oil Corp, Sinopec	1.5	2.3	Q4 - 2014	2019	TransCanada's Prince Rupert Gas Transmission Project
5. Prince Rupert LNG*	Spectra, BG Group, CNOOC Gas and Power Group	1.8	2.7	2017	2020	Westcoast Connector Gas Transmission Project
6. LNG Canada Gas*	Shell, Kogas, Mitsubishi, PetroChina	1.5	3.1	2015	2018	TransCanada's Coastal GasLink Pipeline Ltd.
7. WCC LNG Ltd*	Imperial Oil, ExxonMobile	3.8	3.8	not available	2021-2023	TBA
8. Aurora LNG	Nexen, Inpex (Japan), JGC Corporation	1.5	3.1	not available	2021-2023	TBA
9. Kitsault Energy	Kitsault Energy	2.6	2.6	2015	2018	TBA
10. Stewart Energy LNG	Stewart Energy	0.64	0.64	2014	2017	TBA
11. Woodside LNG	Woodside Petroleum	Expression of interest; no public project announcement				
12. Grassy Point LNG 4	SK E&S (South Korea)	Expression of interest; no public project announcement				
13. Steelhead LNG	Steelhead LNG Corp	Expression of interest; no public project announcement				
14. Discovery LNG	Quicksilver Resources Canada	Expression of interest; no public project announcement				
15. Woodfibre LNG*	Pacific Oil & Gas	0.15	0.27	Fall 2014	2017	Reinforce the existing FEU systems
Total		**15.27**	**20.2**			
Source: Northwestern Institute and Other Various Reports						

* NEB LNG Export Licence has been approved
** The Final Investmant Date (FID) are estimations and can be changed at anytime without notice.
Note: Douglas Channel LNG first aimed to have a Final Investment Decision in 2014 with an exportation date in 2015. However, this will be delayed as LNG Partners LLC sought a court-sanctioned re-organization last year due to financial issues with the project.

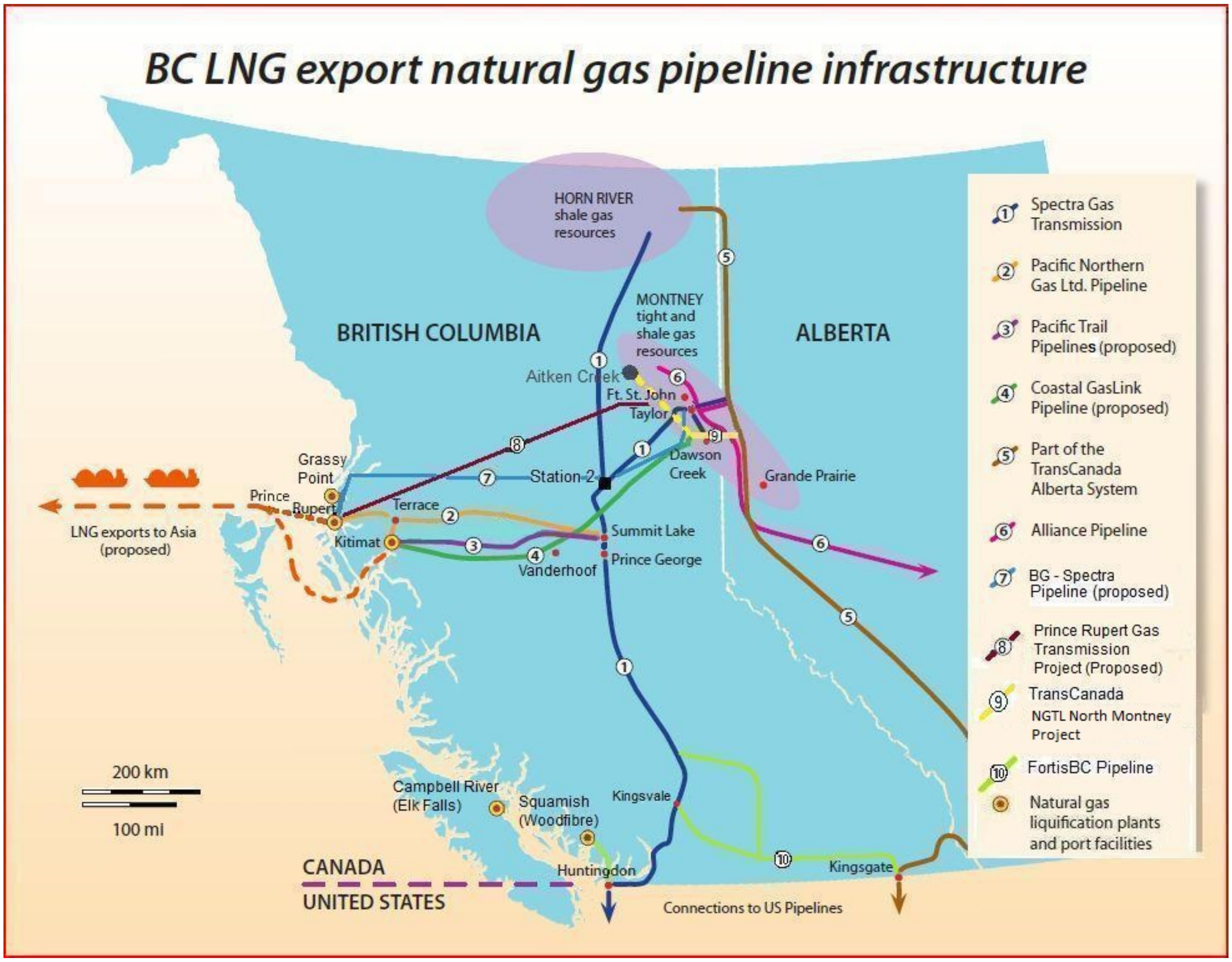
The larger infrastructure projects requiring new pipeline construction typically need long lead times to develop and complete, and require significant financial commitments. Several projects are in the front-end engineering and design or environmental assessment stage of development, however, at this time none of these projects have reached a final investment decision whether or not to proceed with a project. Given the early stage of these proposals, there continues to be considerable uncertainty about how many projects will actually proceed and what gas volumes need to be produced to serve these facilities.

4.1.2 Project Pipeline Routes

The gas supply for export projects will tie into infrastructure that either exists today or will need to be expanded in order to be able to access production from the Montney, Horn River, Cordova, and Liard shale basins. A large portion of the land leases in these basins are now owned by one or more partners participating in an LNG export project. However, not all projects have members who have ownership rights to a lease. Therefore, it is possible that some of these projects will need to purchase supply from existing market hubs, such as Station 2 that interconnects to the Spectra system or with AECO/NIT that interconnects with the NGTL system.

Figure 1 a map illustrating conceptual routes for the proposed pipelines from supply sources to subsequent export terminals in the Kitimat/Prince Rupert area. Given the early stage in the project development process, final pipeline routes and their tie into existing Spectra or NGTL infrastructure may change from what has been announced publicly.

Figure 1: Potential Pipeline Routes in BC for the LNG export market[15]



4.2 *IMPLICATIONS ON THE REGIONAL GAS MARKETPLACE*

Currently the AECO/NIT market hub (NGTL) physically handles approximately 10 billion cubic feet (Bcf)/day, while Station 2 (Spectra) at approximately 2 Bcf/day. Much of the new infrastructure development in the Northeast BC is concentrated on connecting to or extending NGTL's Alberta based system. However, liquidity at the Station 2 market hub could be affected in the future if significant new infrastructure in northeast BC is built that bypasses the Spectra system. Greater liquidity at Station 2 could be achieved by better cost effective connectivity

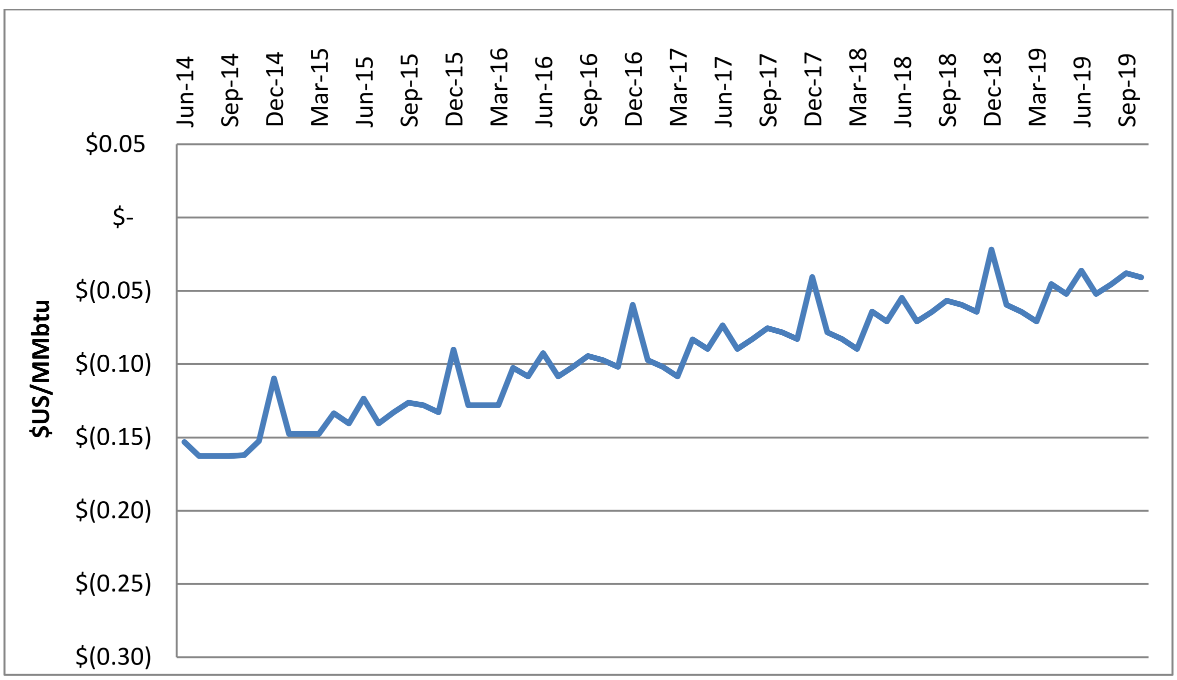
[15] Fraser Institute Studies in Energy Policy October 2012 Laying the Groundwork for BC LNG Exports to Asia and FortisBC additions based on project announcements.

between the Spectra and TransCanada systems, which would entail the construction of additional facilities so that more supply can flow to and from the NGTL system under a more equitable tolling mechanism.

These developments would have an impact on how Station 2 trades in relation to AECO/NIT. In the past, Station 2 has traded at a premium to AECO/NIT in winter and is discounted in the summer. This trading relationship exists because these two trading hubs currently serve two very different markets. Station 2 serves a much smaller winter seasonal market, which has the effect of driving prices higher in the winter when demand is at its highest. In summer this reverses because loads are substantially lower. Greater connectivity to the TransCanada system by producers traditionally transporting on Spectra T-North to serve Station 2 would give them more options for moving production to other markets during the summer and give downstream shippers more options for accessing supply in general.

The impact on price as a consequence of these changes could be twofold. It's possible that Station 2 could continue to trade at a discount relative to AECO/NIT during the period of production ramp-up in BC and trade closer to AECO/NIT as greater BC-Alberta connectivity is driven by LNG export projects. This tightening of the differential between Station 2 and AECO/NIT towards the end of the decade is illustrated in current forward prices. Figure 2 shows that the basis differential between Station 2 and AECO/NIT is expected to tighten as the end of the decade is approached.

Figure 2: Forward Station 2 - AECO/NIT Basis Differential[16]



[16] Source: data provided by One Exchange using forward prices on April 24, 2014.

5. TRANSCANADA AND NGTL SYSTEM UPDATE

By way of clarity for this Section, NGTL is an affiliate of the NEB regulated company, TransCanada Corporation, which transports natural gas produced in British Columbia and Alberta to various markets in North America. TransCanada is also involved in the development of BC regulated pipelines that transport gas from NGTL to a number of proposed LNG facilities on the coast of BC. Collectively, NGTL and TransCanada are involved in a number of initiatives that could impact FEI's ability to cost effectively access secure and reliable supply in the future at fair market prices in BC. These relate to TransCanada's involvement in BC LNG export projects and NGTL's pipeline system extensions from within BC. FEI relies on TransCanada's NGTL and Foothills BC systems to transport AECO/NIT supply to and from storage locations in Alberta and to move supply from Alberta to the FEI system. The following subsections discuss developments in each of these areas.

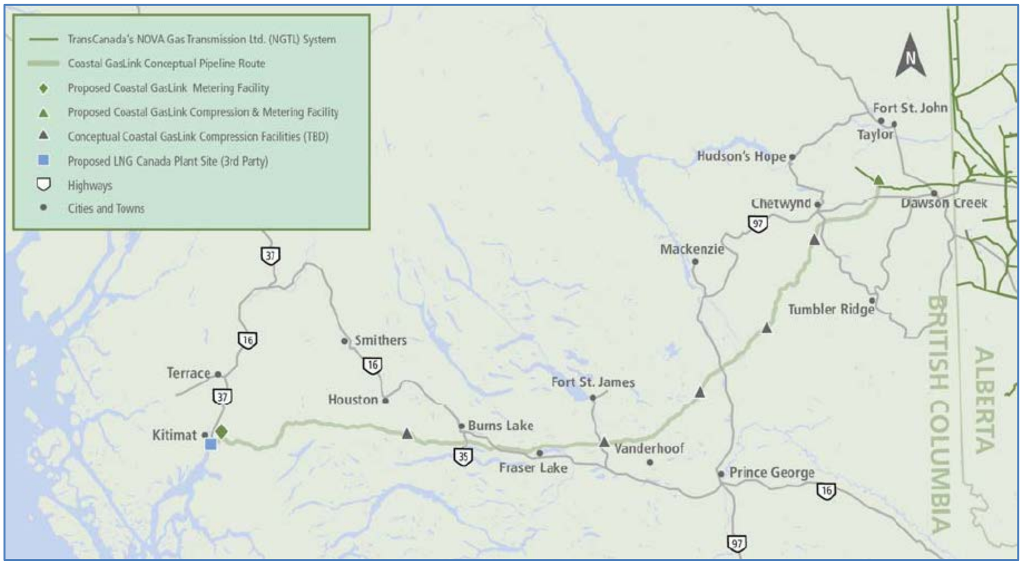
5.1 *BC LNG EXPORT DEVELOPMENTS*

5.1.1 Coastal GasLink Pipeline Project

In June 2012 TransCanada announced that it had been selected by Shell Canada and its partners (LNG Canada) to design, build, own, and operate the proposed Coastal GasLink project. This pipeline will be used to transport natural gas from the Montney gas-producing basin as well as potentially other areas to LNG Canada's planned liquefaction terminal located near Kitimat. It will originate from a location near Groundbirch, BC, where it will tie into TransCanada's existing NGTL system.

The pipeline is expected to cost approximately $4 billion to construct and be placed in service by 2020. It is planned to be 650 km long, 48-inch in diameter, and provide an initial capacity of more than 1.8 Bcf/day and capable of being expanded to flow 5 Bcf/day.

Figure 3: Conceptual route of the Coastal GasLink Pipeline.[17]



NGTL claims that the Coastal GasLink will also provide options for other shippers to access gas supplies through an interconnection with TransCanada's NGTL System and the AECO/NIT market hub. NGTL plans on establishing a Transportation By Other (TBO) arrangement for a portion of the capacity of this pipeline from the current termination of the NGTL Groundbirch segment near Groundbirch in northeast BC, to a point near Vanderhoof, BC. This will allow NGTL to effectively extend the NGTL system to near Vanderhoof and roll the costs of the TBO arrangement into the existing NGTL System. NGTL did not offer any receipt or delivery points other than at its origin near Groundbirch and at its terminus near Vanderhoof in its open season.

5.1.2 Prince Rupert Gas Transmission Project

In January 2013 TransCanada announced that it had been selected by Progress Energy, a subsidiary of Petronas of Malaysia, to design, build, own, and operate the proposed Prince Rupert Gas Transmission Project. This pipeline will be used to transport natural gas from the North Montney gas-producing region, at a point called Mackie Creek on NGTL's proposed North Montney Project, to Pacific Northwest LNG's planned liquefaction terminal located in Port Edward, near Prince Rupert, BC.

The pipeline is expected to cost approximately $5 billion to construct and be placed in service by late 2018. It is planned to be 750 km long, 48-inch in diameter, and provide an initial capacity of more than 2 Bcf/day and capable of being expanded to flow 3.6 Bcf/day.

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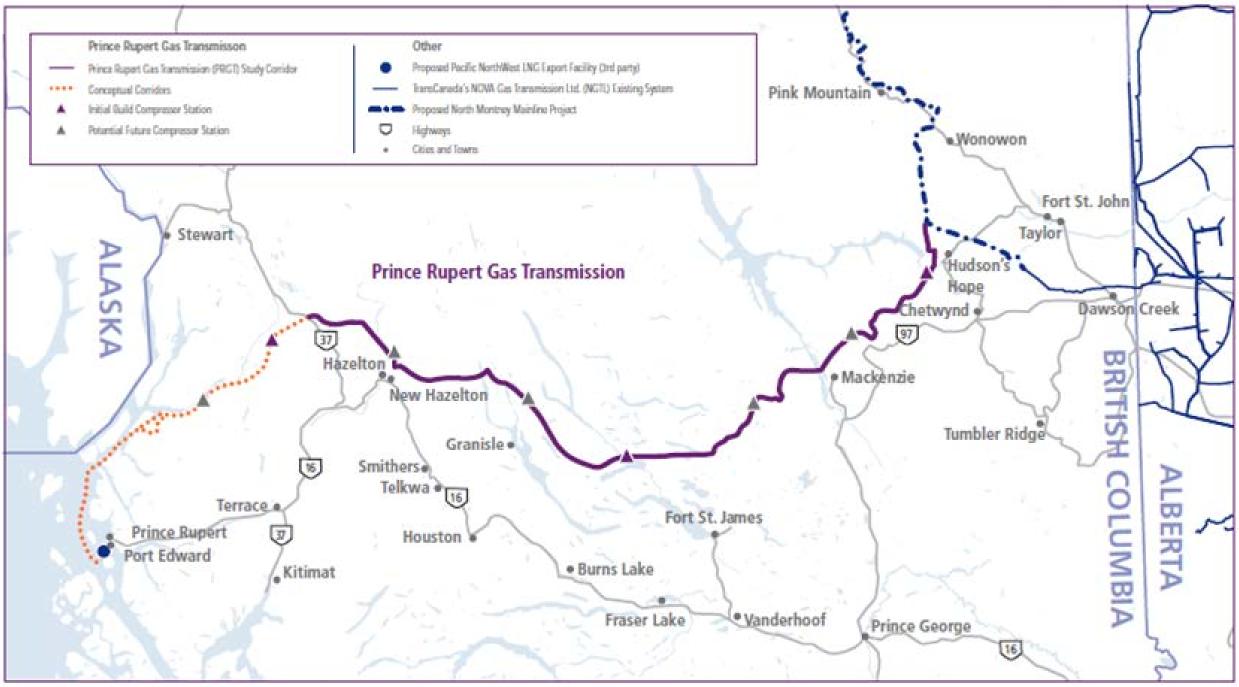
[17] TransCanada, http://www.coastalgaslink.com

Figure 4: Conceptual route of the Prince Rupert Gas Transmission Project.[18]



NGTL plans on a 306 km extension of the NGTL system from Groundbirch (Saturn section) into the north Montney region near Kahta (discussed in subsection 4.2) in order to provide the Pacific Northwest LNG project access to supplies from both the Montney basin and access to the AECO/NIT market hub (this extension, the North Montney Project, is discussed in the next section). The Prince Rupert Gas Transmission Project would tie into the southern portion of this extension. NGTL does not plan to connect this pipeline to any part of the Spectra system at this time. However a number of the potential receipt points are already connected to Spectra, such as the Aitken Creek storage facility, the Aitken Creek gas plant and those at Farrell Creek and Buckinghorse.

5.2 *NORTH MONTNEY PROJECT*

TransCanada is planning to seek approval to extend the NGTL system from the terminus of the Groundbirch (Saturn) section 306 km to the north. This extension is expected to be a 42-inch diameter pipe and cost approximately $1.7 billion ($1.66 billion 2013$) to construct. The main purpose of this extension is to connect to the Prince Rupert Gas Transmission Project and to access north Montney production planned by Progress Energy. This will also physically connect the extension to the Aitken Creek Storage facility and then about 100 km further north to Kahta. This extension will be able to access the bulk of the production expected to be developed in the North Montney play. Figure 5 provides a map of the proposed route of the project.

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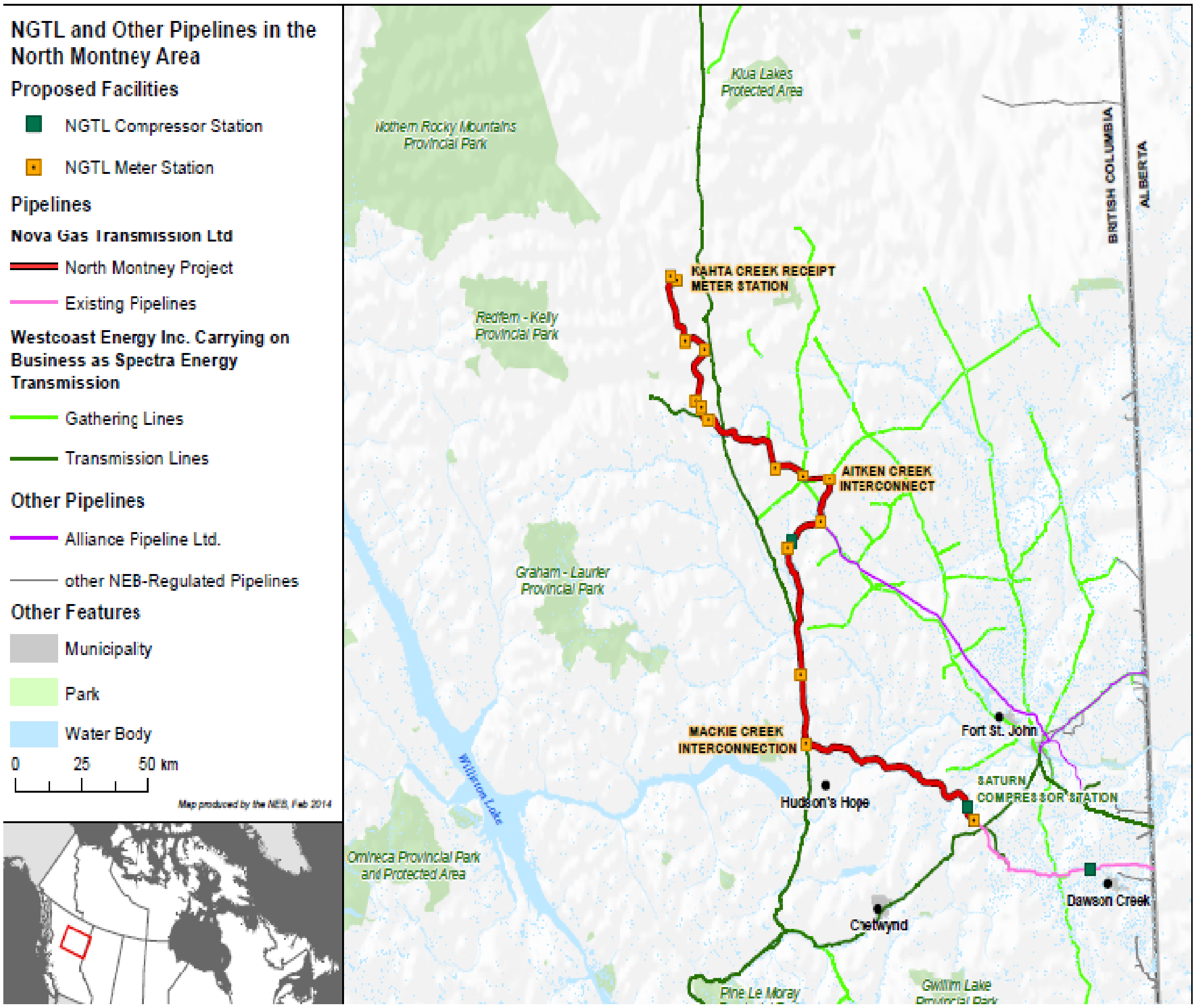
[18] TransCanada, http://www.princerupertgas.com/wp-content/uploads/2013/08/PRGT-project-brochure-March-2014.pdf

Figure 5: North Montney Extension[19]



The North Montney play is currently the most active drilling area in BC. At this time about 30% of production flowing on Spectra's T-North system is produced in this area. NGTL's proposed pipeline is capable of accessing virtually all of this supply and parallels much of Spectra's Ft. Nelson Mainline from Altares to Kahta Creek. NGTL proposes to access seven existing and new processing plants and a further seven processing plants that are in the planning stage that are expected to be in service by 2019. In addition, NGTL proposes to establish a receipt/delivery point at Aitken Creek capable of delivering/receiving 1 PJ/day from the storage facility, which is the only underground storage facility in BC and provides liquidity at Station 2.

[19] Map included in the North Montney Application NEB Information request 2.50.

In recent years production has continued to decline behind Pine River and Ft. Nelson as a result of relatively low gas prices. Until gas supply prices increase, it is expected that this decline in production from these locations will continue. As such, Station 2 is becoming increasing reliant on the continued development of supply in the North Montney area.

FEI has a number of concerns with respect to the application by NGTL and its potential impact on customers including:

- a reduction of liquidity at Station 2 as a result of a reduction of Aitken Creek involvement in the marketplace and a decline in Station 2 supply;
- upward pressure on the price of gas at Station 2 as a result of the need to attract gas flowing to Alberta or from AECO/ NIT, which results in the Station 2 price being set at the NIT level when it is necessary to attract Alberta flow;
- upward pressure on the T-North and T-South tolls as a result of less gas flowing on Spectra; and
- the probability of further extensions into BC by the NGTL system if the North Montney Project is successful, which potentially further reduces supply flowing onto Spectra's systems.

As a result of these concerns, FEI is actively intervening in the North Montney proceeding with the NEB to protect its customers' interests.

5.3 *POTENTIAL FOR A KOMIE NORTH 2 PROJECT*

In 2013 the NEB denied NGTL's proposed Komie extension into the Horn River basin. However, with encouraging drilling results in the Liard Basin, and to the extent that gas commodity prices rise to a level where Horn River drilling could resume again in earnest, it is expected that NGTL will likely apply to the NEB to extend its Horn River pipeline through the Horn River Basin to the Liard basin. Such an extension however, will likely be dependent on the outcome of the North Montney Project.

If NGTL extends to the Liard basin in this manner it will have the potential of picking up a significant portion of production in the Horn River basin that it does not already access. It would also have access to the Liard basin, which is the newest in northeast BC. Such an extension would potentially significantly reduce supply flowing to Spectra's Fort Nelson plant, whose importance increases should the North Montney project be constructed.

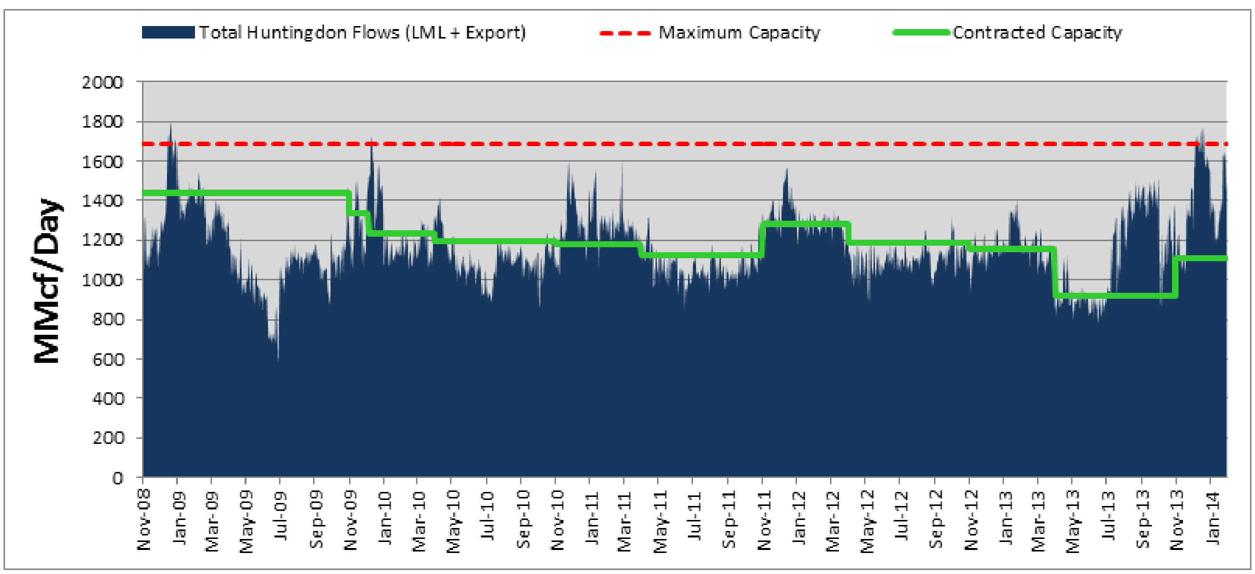
6. SPECTRA SYSTEM

Since the vast majority of FEI's supply is transported on Spectra's T-North and T-South systems, it is important for these systems to remain competitive with other competing infrastructure proposals to ensure continued access to natural gas at Station 2 and improving it in the future. The potential expansion of current markets, particularly in the Lower Mainland, with high load factor process load, should encourage producer commitment to BC and support gas flows south via Spectra's systems, providing FEI with more secure access to supply over the long term from production in BC. This could also lead to further expansions of the Spectra T-South/T-North systems, as well as developing the Kingsvale-Oliver Reinforcement Project (KORP) in conjunction with a Spectra T-South expansion. Spectra also continues to offer the T-South Enhanced Service utilizing a portion of the FEI's system to deliver gas from Station 2 to Kingsgate.

6.1 *SPECTRA ENERGY T-SOUTH/T-NORTH EXPANSION*

The PNW region, including British Columbia, has historically been a winter peaking market and the regional pipeline and storage resources have been developed to meet this peak demand. As a result, Spectra's T-South system is substantially full during much of the winter months. However, this demand is comprised of firm and interruptible pipeline demand as shown in Figure 6.

Figure 6: Spectra T-South System Flows



If the new regional baseload market develops in southern BC and the PNW it would absorb some of the available firm capacity on the Spectra pipeline. Since there would be less interruptible capacity available to shippers to meet winter peak demands, some interruptible shippers would likely "firm" up their capacity needs rather than risk interruption. The outcome of this development would likely lead to some combination of pipeline expansions and/or market area storage expansion solutions, triggering future expansion plans to be implemented sooner than presently planned. The challenge for Spectra is balancing the possible requirement to expand their T-South system and the time it takes to construct an expansion, with the significant amount of uncontracted capacity (but not unutilized) that it currently has available. Spectra has indicated that it could expand up to 200 MMcf/day by 2017 and up to a cumulative 1 Bcf/day by 2020 if required by the market.

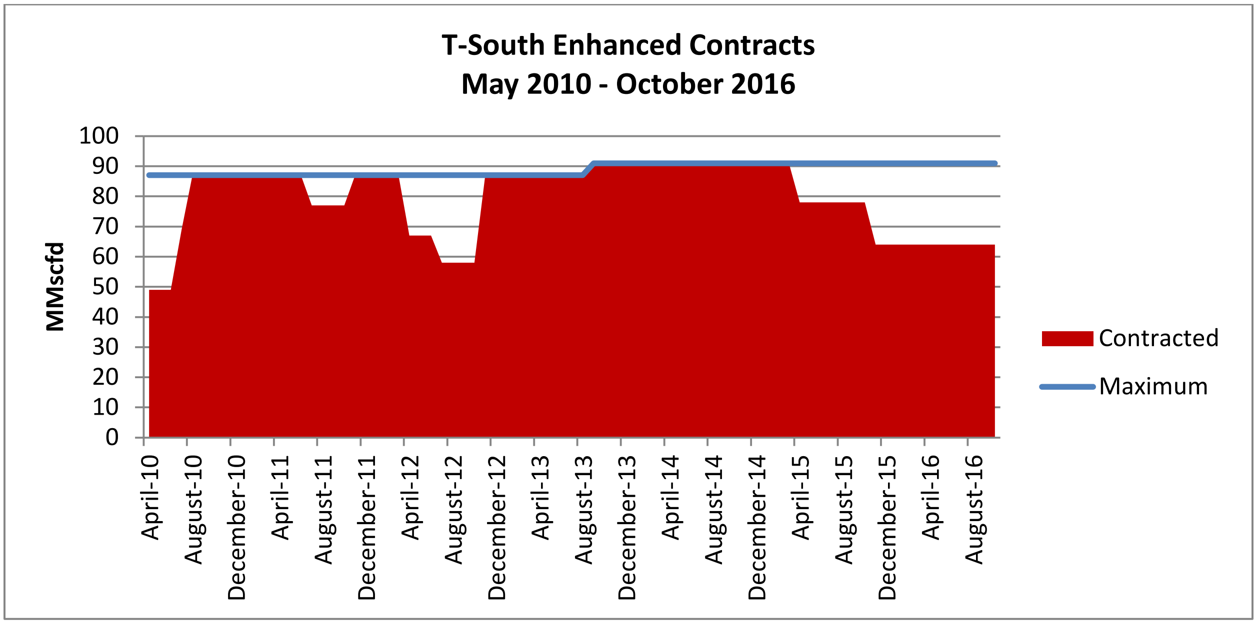
Spectra's T-North system is fully contracted at this time. In order to meet the possible expansions on the T-South system, Spectra will also require expanding its T-North system. Spectra is currently exploring the potential to expand both the T-South and T-North systems, with some portion of capacity in service as early as 2017. The T-South toll impact will be dependent on the amount of expansion and the use of existing uncontracted capacity on the system.

6.2 *T-SOUTH ENHANCED SERVICE*

The T-South Enhanced Service has been in effect since May 2010 and continues to deliver significant benefits to FEI customers. In 2013 Spectra Energy and FEI further extended this service to October 2016 and increased the total volume from 87 MMcf/day available to 91 MMcf/day.

T-South Enhanced remains fully contracted until March 31, 2015 (at which time the T-South Enhanced contracting levels drop to 85 percent contracted). FEI customers have benefited from both the revenue received from Spectra Energy for the SCP capacity and the T-South toll reductions from the service. FEI customers are expected to receive a cumulative benefit of approximately $50 million for the 2010 to October 2016 time period. Figure 7 illustrates the historical and current contracting levels of the service from initial offering in May 2010, through to the extension end date of October 2016.

1 **Figure 7: Spectra T-South Enhanced Service Contracted Levels**



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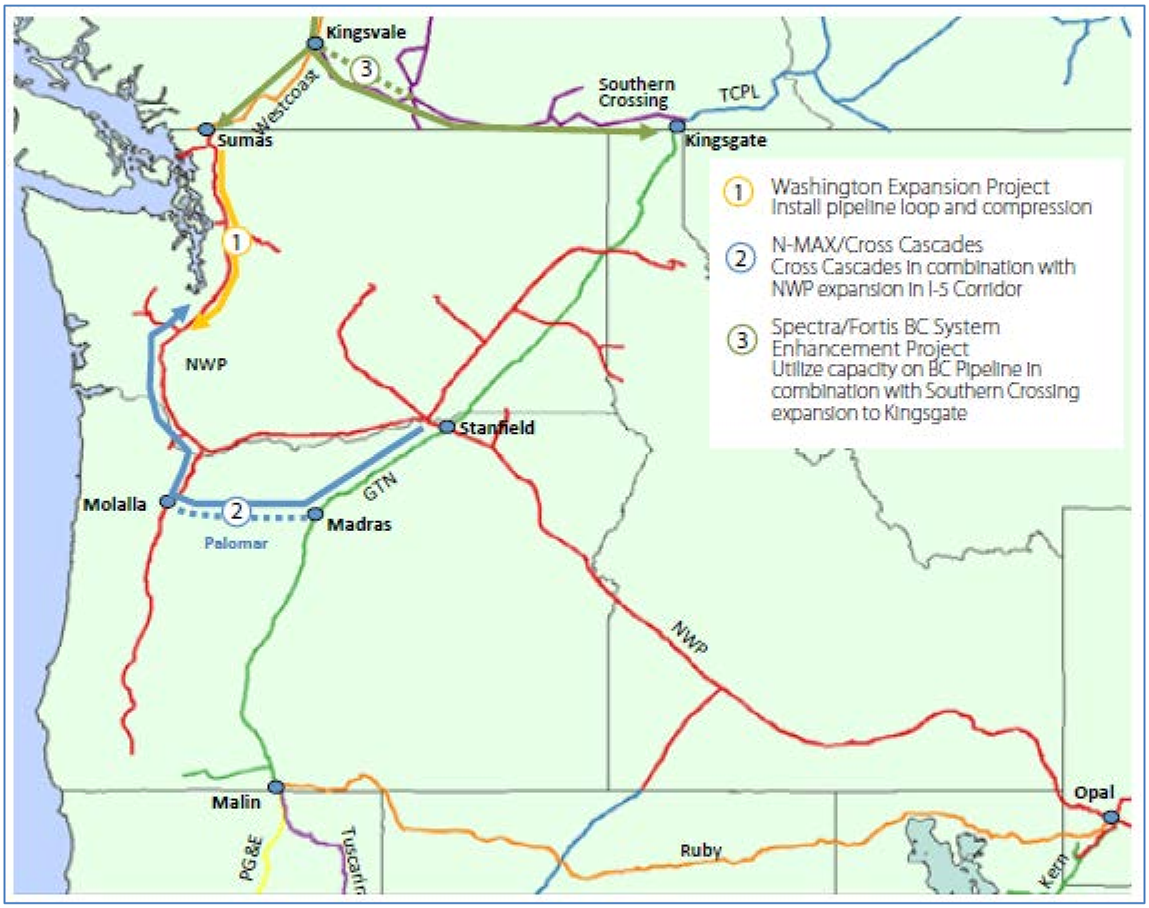
7. U.S. PACIFIC NORTHWEST INFRASTRUCTURE UPDATE

This subsection provides an update on proposed major pipelines and infrastructure projects within the PNW region of the U.S. These projects will impact gas flows and pricing dynamics within the region if they proceed. A map of the projects is provided in Figure 9.

Figure 9: U.S. PNW Infrastructure Projects[20]



7.1 *WASHINGTON EXPANSION PROJECT*

In response to a request for a potential incremental 750 MMcf/day of capacity primarily to serve a proposed LNG export facility located in Oregon, NWP is proposing to construct the Washington Expansion Project. The project consists of 140 miles of 36-inch diameter pipe to be constructed in ten different segments in or near NWP's existing right-of-way along the I-5 corridor between Sumas, WA, and Woodland, WA, plus additional compression at five existing compressor stations. In conjunction with this project, NWP is also proposing an incremental scalable expansion from Sumas to markets in the I-5 corridor as far south as Molalla, Oregon.

[20] Northwest Gas Association 2014 Gas Outlook.

This phase of the project is not contingent upon the expansion proposed in support of the Oregon export LNG project and could potentially go in service fall of 2016 to meet other possible I-5 incremental demand requirements. If the NWP Sumas south expansion were to proceed, an expansion on systems upstream of Sumas would likely be required, which could support an expansion on Spectra's T-South/T-North systems or a combination of KORP/T-South.

7.2 N-MAX/CROSS CASCADES EXPANSION PROJECT

NWP is working with the current Cross Cascades pipeline project sponsors (Northwest Natural and TransCanada GTN) to develop the project in conjunction with an expansion of the existing NWP system. The Cross Cascades project would consist of a 160 km pipeline that would run from GTN's mainline in central Oregon to a NWN/NWP hub near Molalla. It would enhance the delivery capacity to the I-5 Corridor. Palomar's initial design capacity is 300 MMcf/day and is expandable to 750 MMcf/day. It would be linked to the N-MAX project on the NWP system to deliver gas to other markets along the I-5 Corridor. It is FEI understands that in order for this pipeline option to be competitive higher contracting levels are required in order to reduce the overall toll.

7.3 SPECTRA/FORTISBC SYSTEM ENHANCEMENT PROJECT (KORP)

FEI continues to evaluate KORP as a resource option for the region. The market has fundamentally changed since the original planning for KORP arising from of the development of interest in new regional potential industrial and LNG export demand resulting from the relatively low gas commodity price environment. However, much of the technical work to date will allow FEI to be in a position to respond quickly when the market opportunity becomes more certain.

KORP consists primarily of a 161 km, NPS-24 pipeline expansion from Oliver to Kingsvale, BC. Up to 300 MMcf/day of new capacity could be provided to the Huntingdon market via Spectra/Kingsvale South Capacity. The reinforcement would further integrate and expand service using available capacity on T-South and FEI's Southern Crossing Pipeline. The bi-directional nature of the system would allow shippers to flow to either Huntingdon or Kingsgate, when demand in BC and the US PNW is low, typically during summer months. This expansion could be in service for 2018 and be made in conjunction with a Spectra T-South expansion.

8. IMPLICATIONS FOR FEI

The need to develop new markets for natural gas production in the WCSB signals significant potential change for the natural gas industry in Western Canada. These developments will require the development of new regional infrastructure proposed to help take advantage of these new opportunities. On the one hand, gas production in Alberta is declining and traditional markets in eastern North America are turning to other sources of supply. One the other, increased demand in Alberta needs to be served and there is the promise of a major new LNG export market and increased regional power generation and industrial demand.

These changes create uncertainty that requires FEI to continue to carefully monitor developments and potentially participate as interveners in future facilities applications that may have a significant impact on its operations. Key activities by FEI in this regard include the following:

- monitor LNG project developments in order to understand the implications these developments may have for the region;
- consider challenging future facilities expansion applications for northeast BC if they appear to harm the liquidity and functioning of Station 2 as a market hub;
- advocate for a potential improved interconnectivity of Spectra and TransCanada's pipeline systems as a means of improving liquidity, pricing stability, and supply availability at Station 2;
- actively pursue contracting for supply with producers at Station 2, especially those expected to increase their production in an effort to serve LNG export demand;
- potentially enter into contracting arrangements for supply with longer terms than have been traditionally negotiated;
- evaluate other options such as plant outlet contracting or increased contracting of BC based storage for supply; and
- explore options for aligning with utilities in the U.S. PNW who are similarly reliant on supply from northeast BC via Spectra's T-South pipeline.

9. CONCLUSION

The preceding review provides an overview of some of the significant changes that are occurring in the natural gas marketplace in western Canada. Many of these changes are driven by the need to address such matters as declining gas production in Alberta, increasing regional demand from industrial, power generation and oil sands demand, and numerous potential LNG export projects. A complicating factor in this environment is the loss by the WCSB of traditional markets in eastern North America, which is the result of shale gas production in new basins located much closer to these traditional markets. The significant supply potential in northeast BC represents the solution to many of these problems, as well as helping to realize many of these new opportunities.

The abundance of natural gas in the WCSB, particularly in BC, is leading to proposals for a number of new key infrastructure developments within the region. Pipeline expansions in BC, Alberta, and the U.S. PNW will move natural gas to existing and new markets, resulting in changes to traditional and regional flow patterns and pricing dynamics.

BC is poised to be in the forefront of various developments that include pipeline, supporting infrastructure, and potentially exporting significant volumes of LNG to Asian markets over the next few years and decade. However, the growth of natural gas production in BC is also subject to various other influences such as pricing of commodity, changing demand dynamics and cost of production. Continued expansion of gas production will benefit consumers in BC as this provides opportunities for gas to be available in BC markets rather than flowing mostly to eastern markets in light of the increased takeaway capacity out of BC.

FEI will continue to evaluate regional developments and marketplace opportunities that will result in increased gas flow through BC, improved marketplace liquidity, security and overall competitiveness for commodity pricing in BC over the long term.

Appendix C

2012 CUSTOMER SURVEY RESULTS

SENTIS
measuring what matters

Alternatives for Managing Natural Gas Price Volatility

High-Level Results

Prepared for:

FORTIS BC

August 8, 2012

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604.566.8912
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Brief Summary

This brief summary presents high-level results for several areas of the FortisBC Alternatives for Managing Price Volatility survey. The survey was conducted among 800 BC residents and 204 BC businesses In June and July of 2012. A full interpretive report of the results is forthcoming.

This summary discusses results related to the following areas of the survey:

- Knowledge and clarity of current bill components
- Preferences regarding the frequency of rate adjustments
- Level of interest in alternative rate options

Following the summary, we have included the results related to these areas as well as the results for the other questions included in the survey.

Understanding the Difference Between Delivery and Commodity Charges

- Less than half of businesses (45%) and even fewer residents (35%) gave responses indicating that they feel confident that they understand the difference between delivery and commodity charges (assigning a rating of either 4 or 5 on a 5-point scale).

- Neither group finds the distinction between these two charges as particularly clear. 36% of residents gave responses suggesting that they find the distinction clear (by rating the clarity of the distinction as either 4 or 5 on a 5-point scale), compared to 45% of businesses.

Separating Basic vs. Delivery; Midstream vs. Cost

- Before they read a description of what each charge relates to, respondents were asked if they were aware, prior to the survey, of what each charge covers.

- Prior awareness of what these charges cover varies substantially across charges. The majority of residents (62%) and businesses (65%) were aware of what the cost of gas charge covers. Similarly, the majority of residents (55%) and businesses (61%) were aware of what the delivery charge covers.

- Prior awareness drops significantly for what the basic charge covers (44% among residents; 33% among businesses) as well as for what the midstream charge covers (30% residents; 22% businesses).

- Prior awareness of what these charges cover does tend to help residents and businesses understand the description of these charges provided in the survey. Based on the descriptions provided, 58% of residents and 63% of businesses feel confident that they understand what the cost of gas covers. However, post-description only 42% of residents and 50% of businesses feel confident that they understand what the mid-stream charge covers.

Separating Basic vs. Delivery; Midstream vs. Cost

- The one exception to this pattern of results is the basic charge—less than half of residents and businesses were aware of what this charge covers prior to the description. However, the majority (57% of residents; 63% of businesses) expressed confidence that they understood the charge after reading the description. This may be because the description of the basic charge is the only description that does not refer to energy units or how the charge is calculated.

- Businesses tended to give higher ratings for the clarity of the separation of the charges than residents did. Overall, 62% of businesses rated the separation between the basic and delivery charge as clear, compared to 50% of residents.

- Also, 51% of businesses gave higher rating for the clarity of the distinction between midstream and cost of gas charges, compared to residents (42%).

- Overall, it is not surprising that the clarity ratings for the distinction between midstream and cost of gas charges are lower, given the lower percentage of customers who feel confident that they understand midstream charges.

Preferences Regarding the Frequency of EPP Adjustments

- Awareness that FortisBC may adjust EPP monthly installment amounts each quarter was higher among residents (44%) than businesses (25%).

- The survey results showed a clear preference among customers for a quarterly adjustment period.

- 61% of residents and 59% of businesses prefer a quarterly adjustment period compared to a longer period between adjustments.

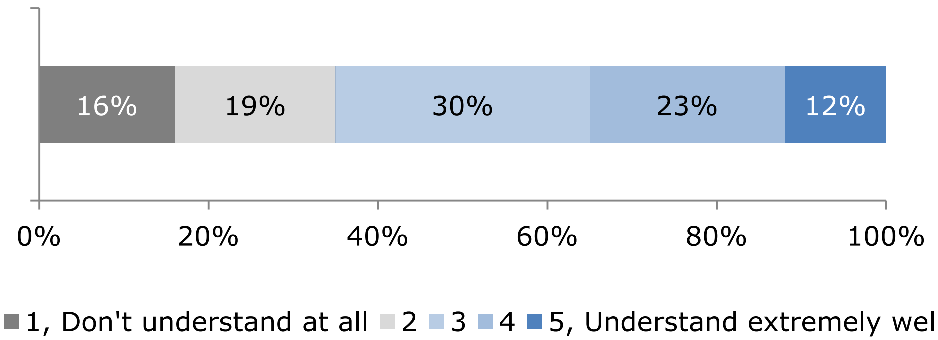
Interest in Alternative Rate Options

- Within both the residential and business groups, customers tended to rate the four options similarly with respect to the ease with which they could understand them.
- Among residents, 55% rated the market rate option as easy to understand, followed by price protect (49%), rate cap (48%) and rate protect (48%).
- Businesses tended to rate each of the options as easier to understand than residents did. Among businesses, 63% rated the market rate as easy to understand, followed by rate cap (60%), price protect (59%) and rate protect (55%).
- When they were asked to rate the likelihood that they would choose each of three options—rate cap, price protect, rate protect—residents and businesses had no clear preference. Among the three options, the rate cap option was perceived somewhat more appealing.
- When they were asked to make a choice among the *four* options, both residents and businesses chose the market rate option much more frequently than the other options. 41% selected the market rate option. The closest other option was price protect—17% among residents, 18% among businesses.

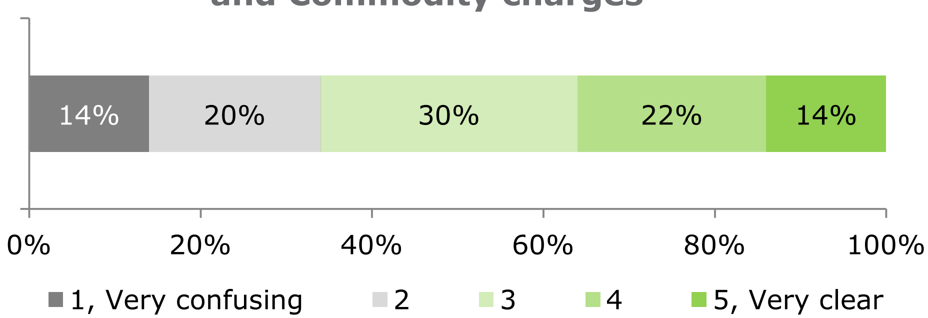
Natural Gas Bill: Delivery vs. Commodity Charges

Residential

Understand difference between delivery charge and commodity charge

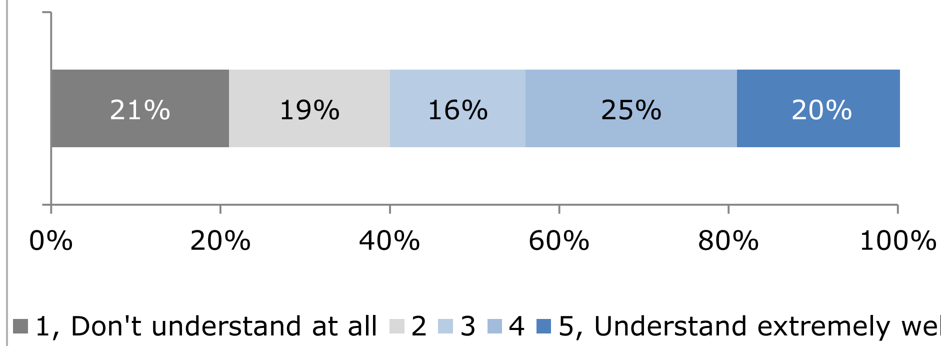


How clear or confusing is it to have bill separated by Delivery and Commodity charges

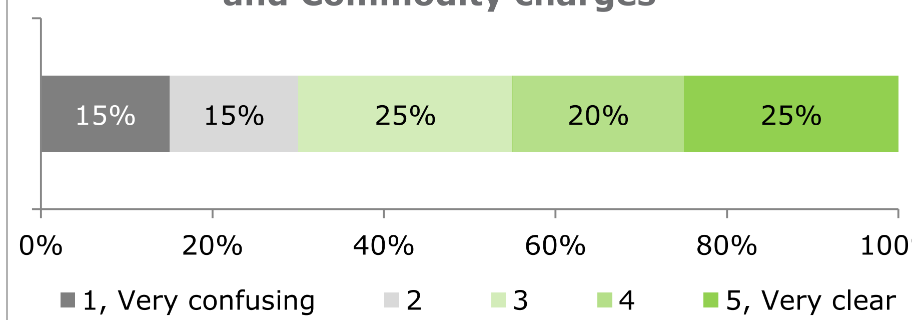


Business

Understand difference between delivery charge and commodity charge



How clear or confusing is it to have bill separated by Delivery and Commodity charges



Natural Gas Bill: Basic, Delivery; Midstream, Cost of Gas

Residential

Aware of what charges cover before reading description

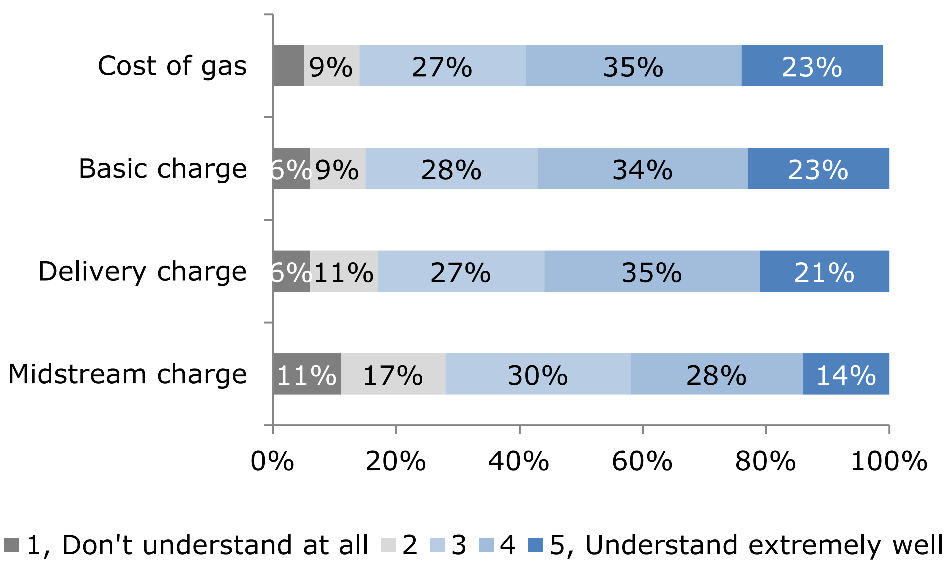
Basic Charge: **44%**

Delivery Charge: **55%**

Midstream Charge: **30%**

Cost of Gas: **62%**

Understanding of charges based on description provided



Business

Aware of what charges cover before reading description

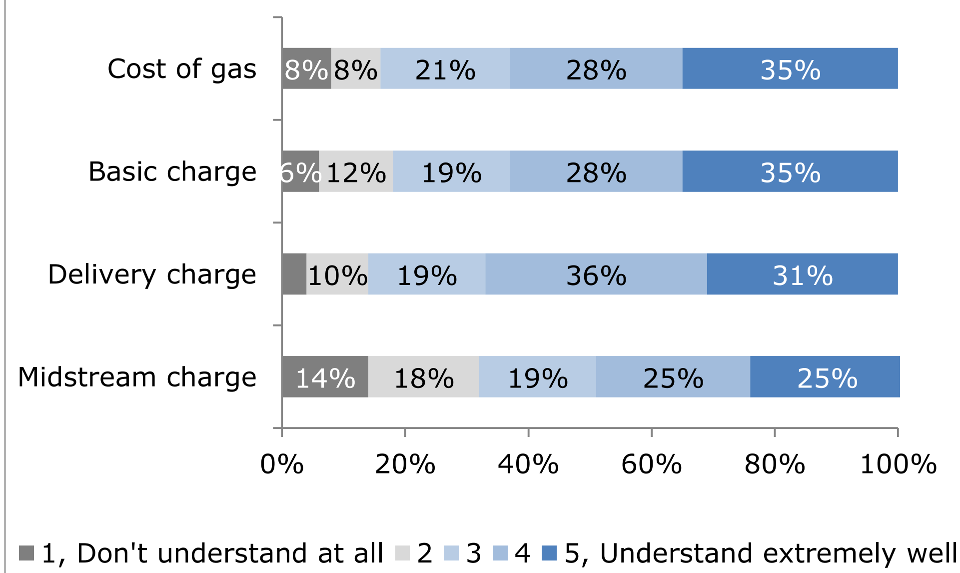
Basic Charge: **33%**

Delivery Charge: **61%**

Midstream Charge: **22%**

Cost of Gas: **65%**

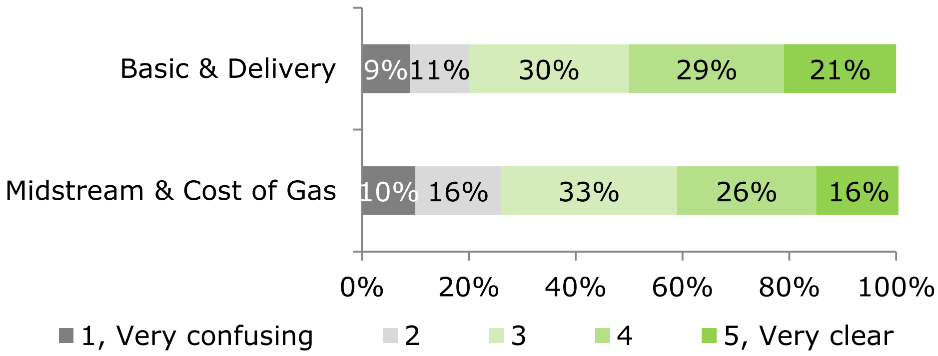
Understanding of charges based on description provided



Natural Gas Bill: Basic, Delivery; Midstream, Cost of Gas

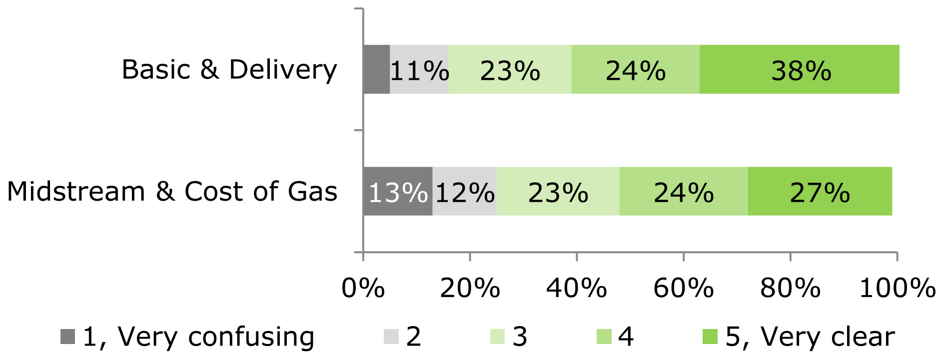
Residential

Clarity of Charges
How clear or confusing is it to have bill separated by:



Business

Clarity of Charges
How clear or confusing is it to have bill separated by:



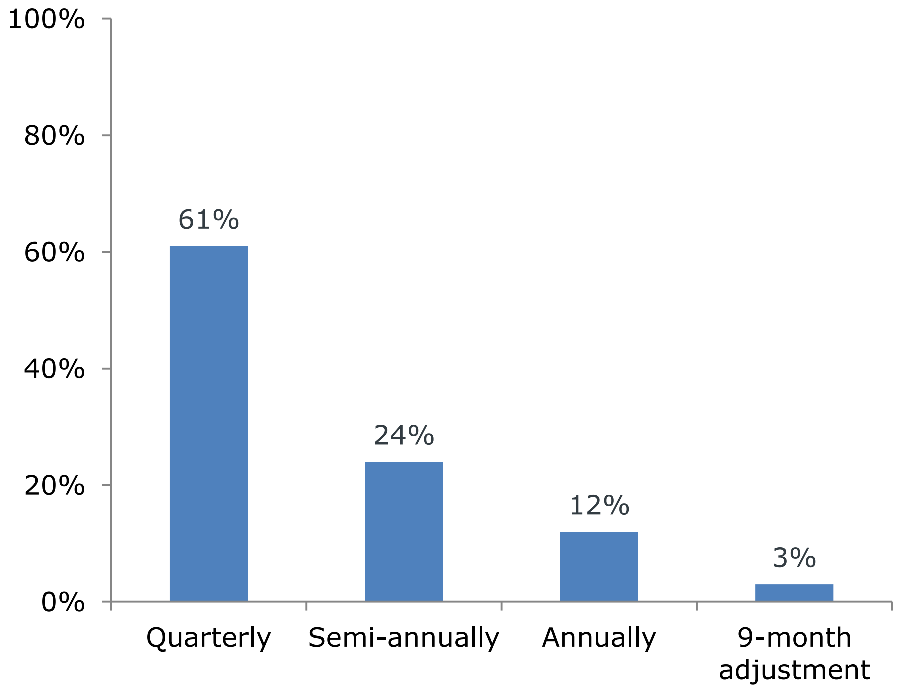
EPP: Awareness of Possible Adjustment & Preferences

Residential

Aware that FortisBC may adjust EPP monthly installments each quarter:

44%

Preferred EPP Adjustment Period

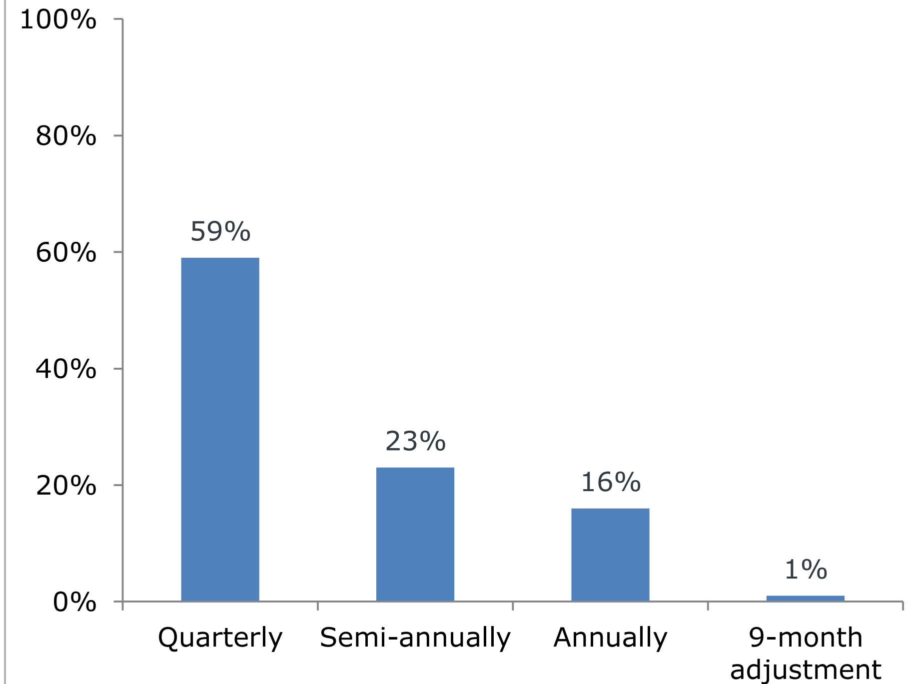


Business

Aware that FortisBC may adjust EPP monthly installments each quarter:

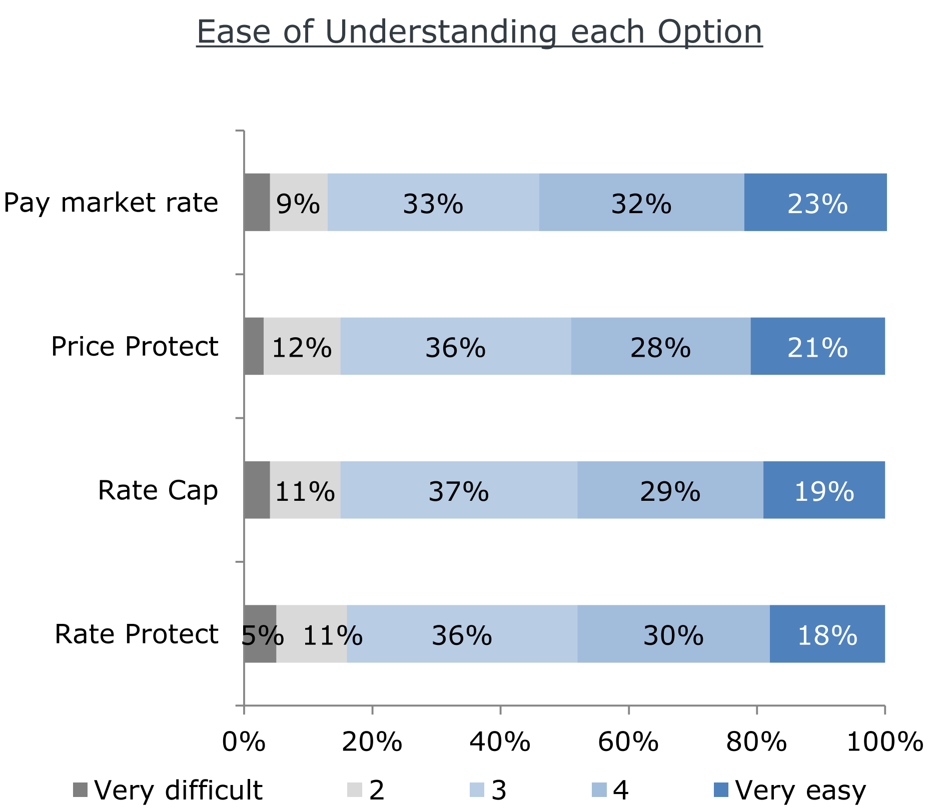
25%

Preferred EPP Adjustment Period

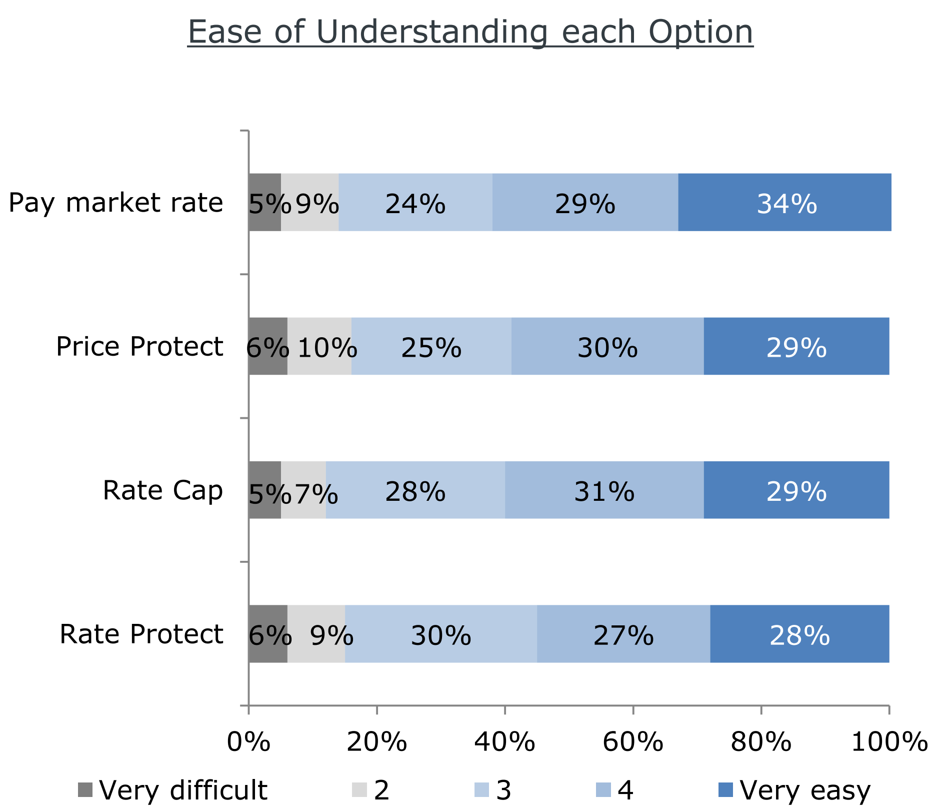


Stabilizing the Cost of Gas: Ease of Understanding Options

Residential

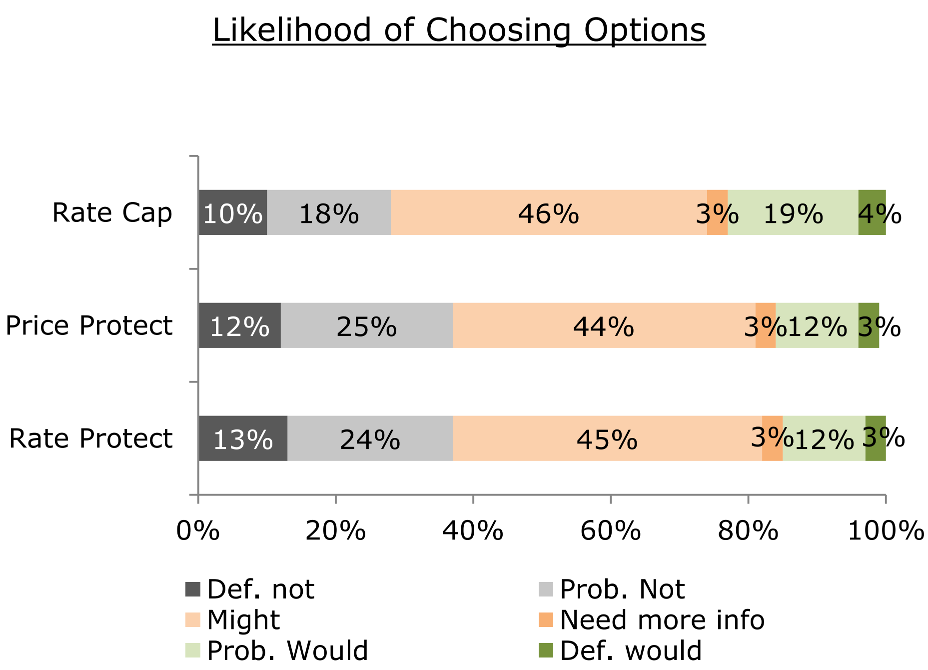


Business

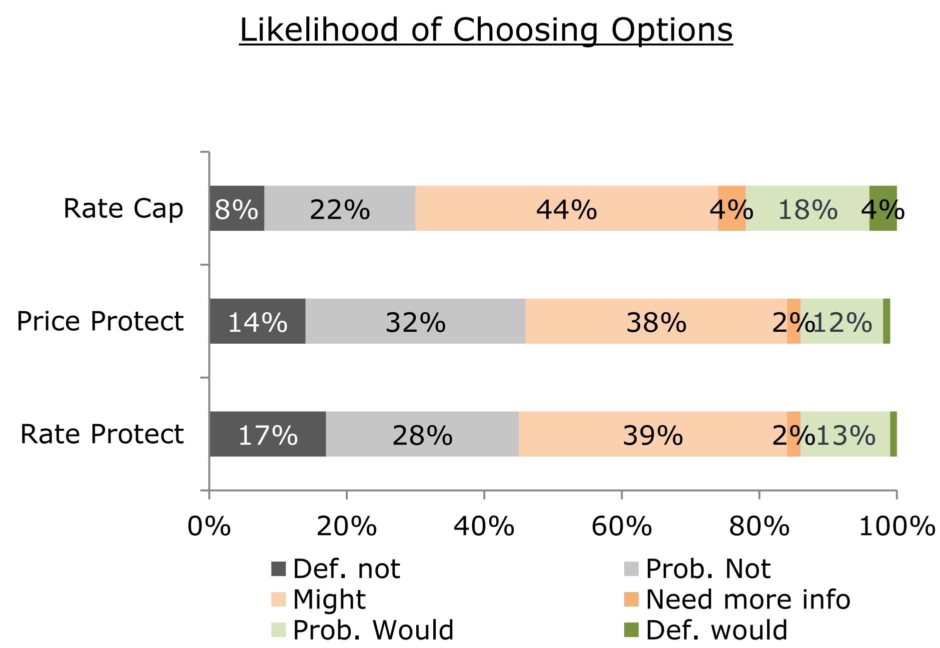


Stabilizing the Cost of Gas: Likelihood of Choosing each Option

Residential



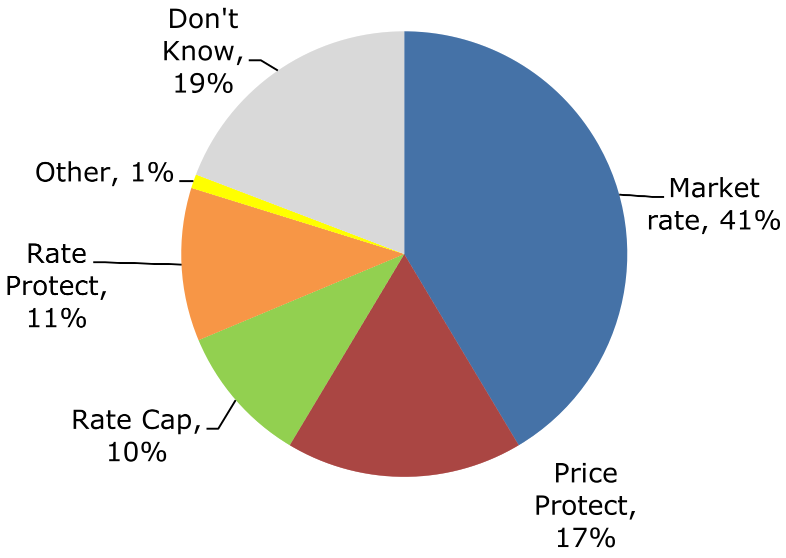
Business



Stabilizing the Cost of Gas: Preference among Four Options

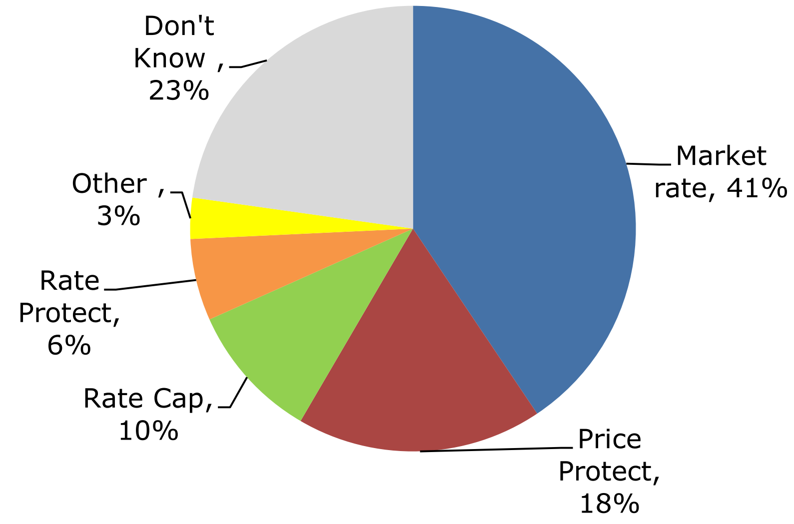
Residential

Preference among Four Options

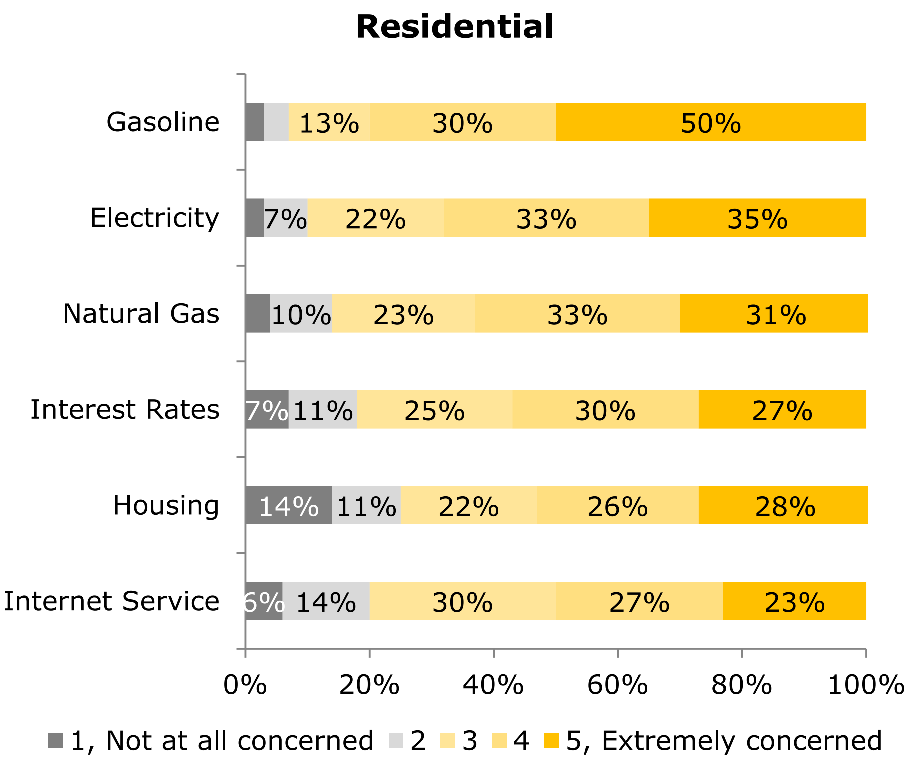


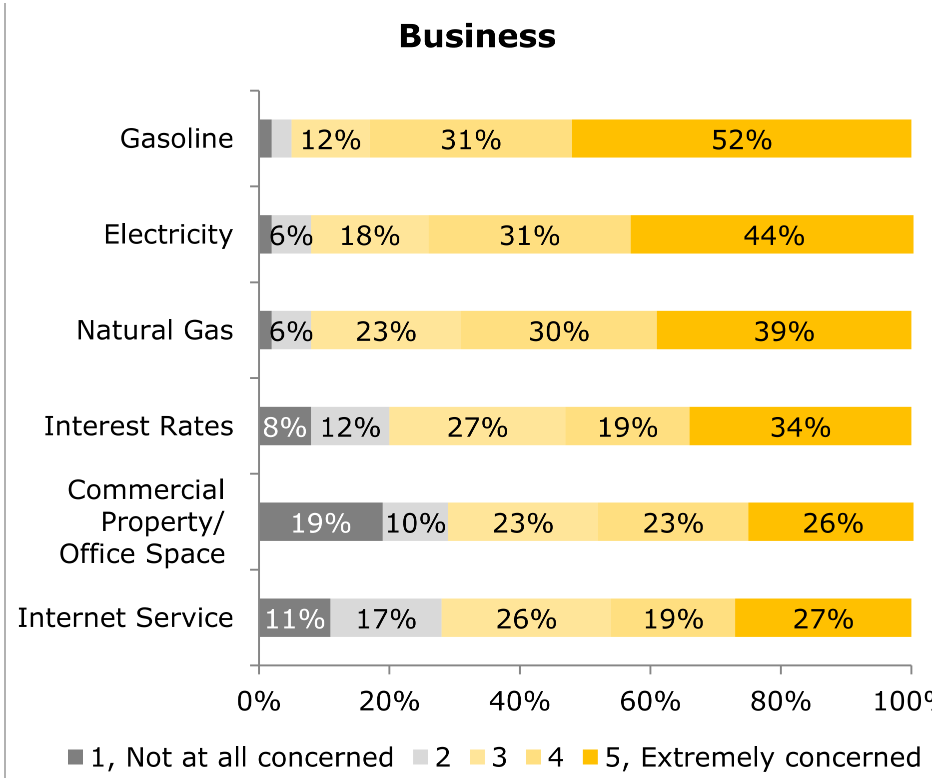
Business

Preference among Four Options



Levels of Concern Regarding Price Increases in Next 3 to 5 Years





Awareness of How Fortis Makes Profit

Residential

Aware that Fortis BC makes a profit only on the delivery of gas:

27%

Business

Aware that Fortis BC makes a profit only on the delivery of gas:

23%

Equal Payment Plan (EPP): Awareness and Participation

Residential

Who Supplies Your Electricity?

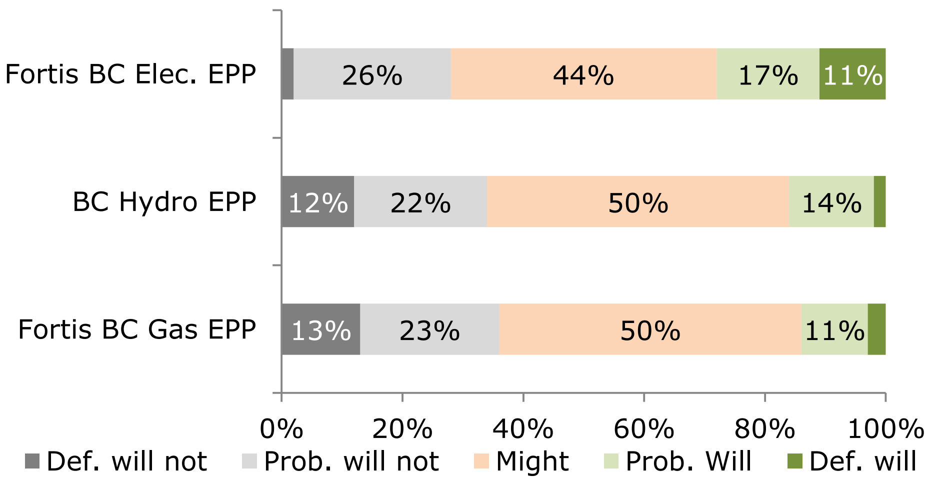
BC Hydro **76%** Fortis BC **24%**

Aware of Fortis BC EPP: **78%**
Signed up for Fortis BC EPP: **41%**

Aware of BC Hydro EPP: **86%**
Signed up for BC Hydro EPP: **45%**

Aware of Fortis BC Electricity EPP: **82%**
Signed up for Fortis BC Electricity EPP: **47%**

Interest in Signing Up



Business

Who Supplies Your Electricity?

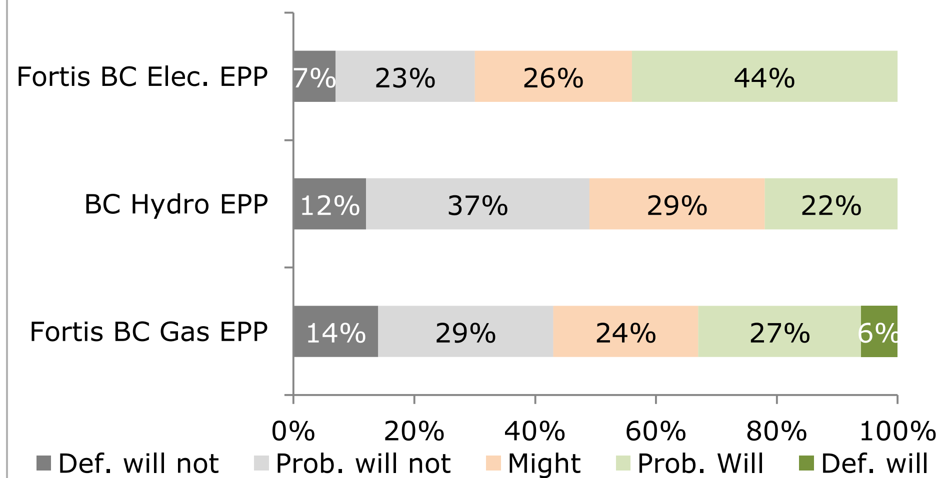
BC Hydro **76%** Fortis BC **24%**

Aware of Fortis BC EPP: **80%**
Signed up for Fortis BC EPP: **13%**

Aware of BC Hydro EPP: **81%**
Signed up for BC Hydro EPP: **16%**

Aware of Fortis BC Electricity EPP: **79%**
Signed up for Fortis BC Electricity EPP: **13%**

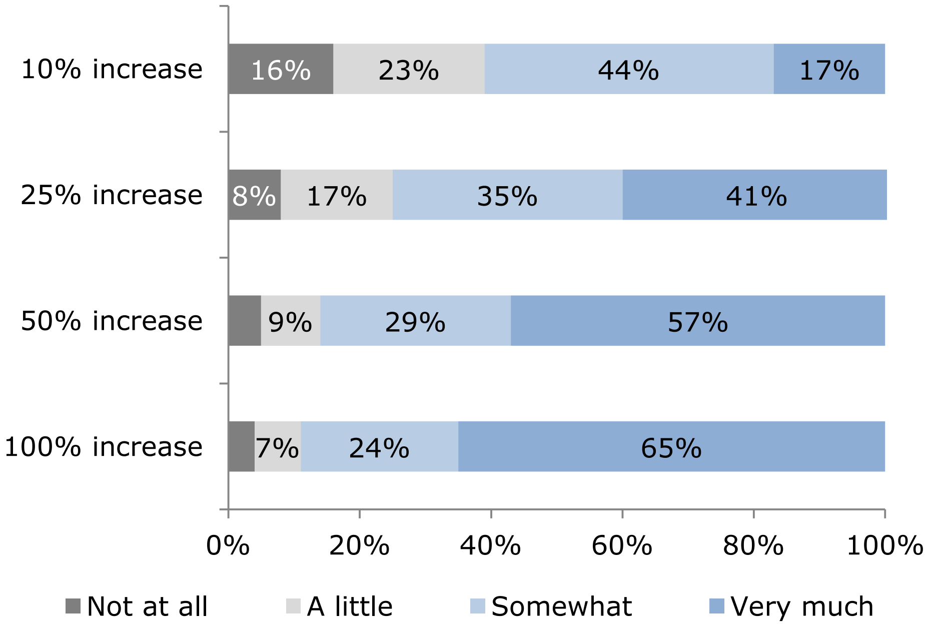
Interest in Signing Up



Impact of Natural Gas Price Increases on Behaviour

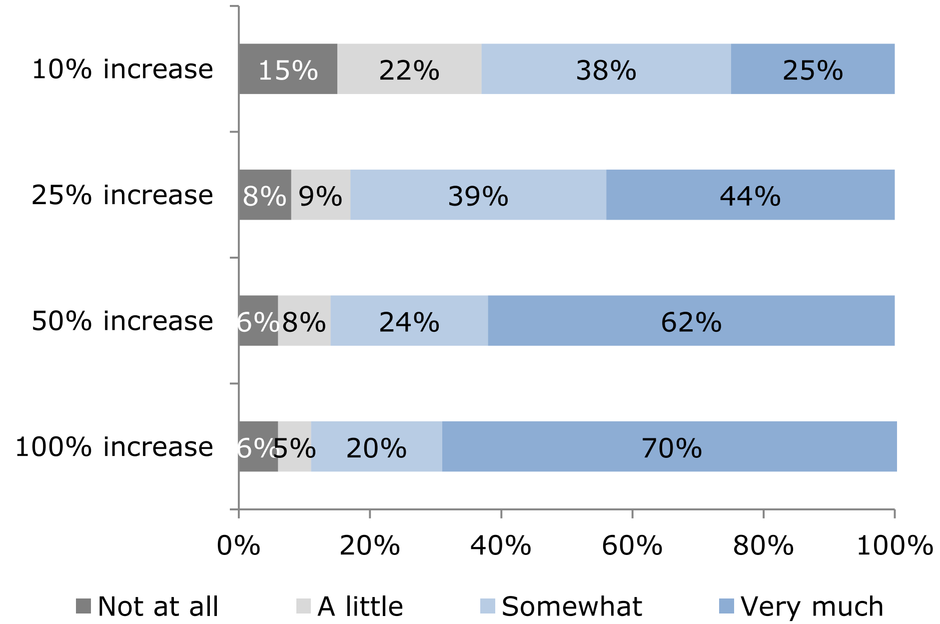
Residential

How much will a 10%, 25%, 50% and 100% price increase cause customers to turn down their thermostat or cut back on other costs?



Business

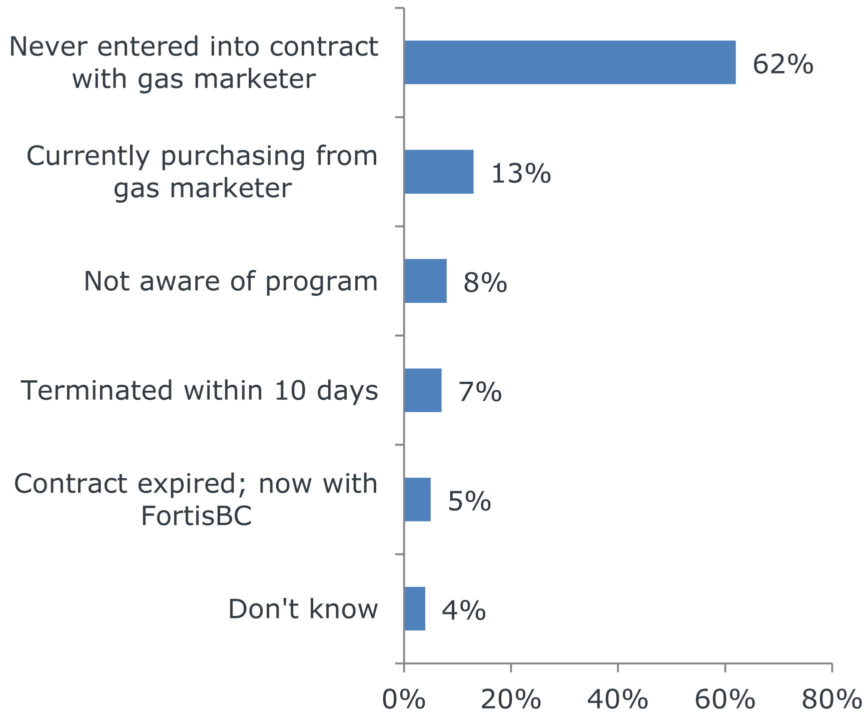
How much will a 10%, 25%, 50% and 100% price increase cause customers to turn down their thermostat or cut back on other costs?



Customer Choice Program: Purchase from Gas Marketers

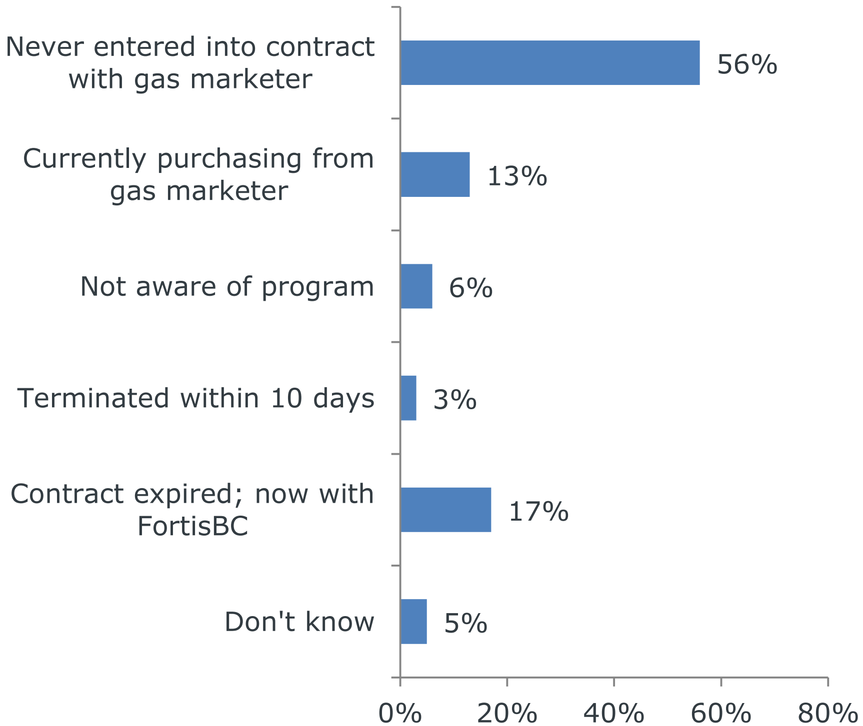
Residential

Experience with Gas Marketers



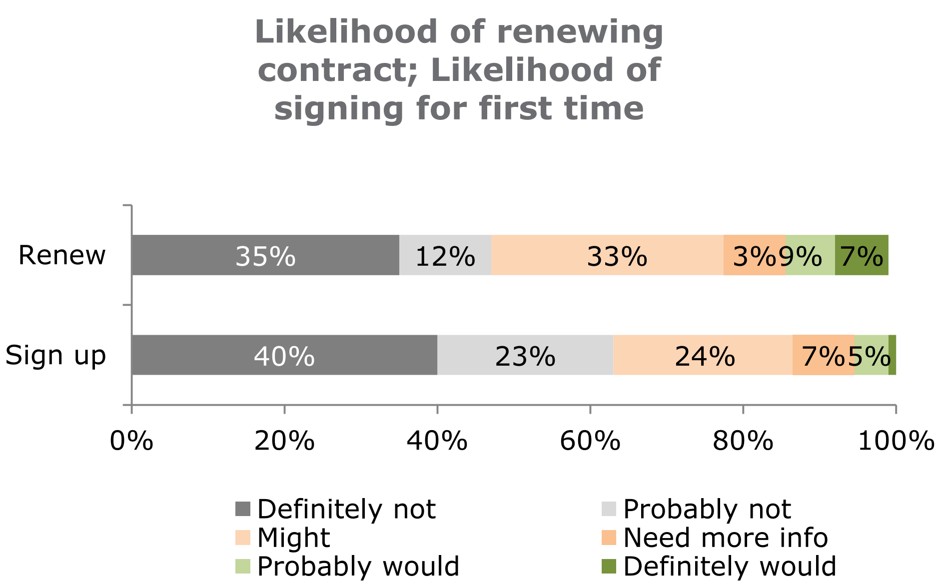
Business

Experience with Gas Marketers

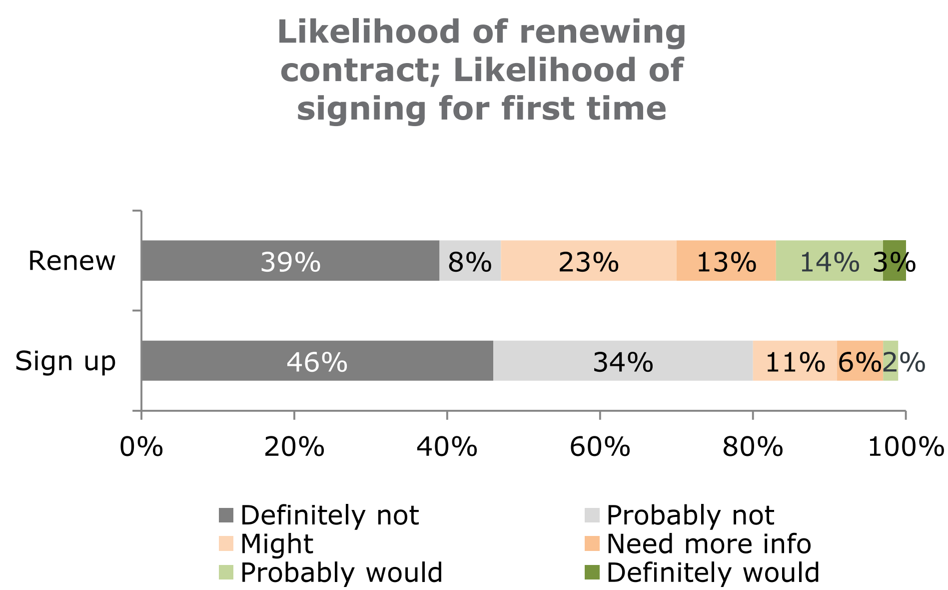


Likelihood to Renew/Purchase from Gas Marketer

Residential



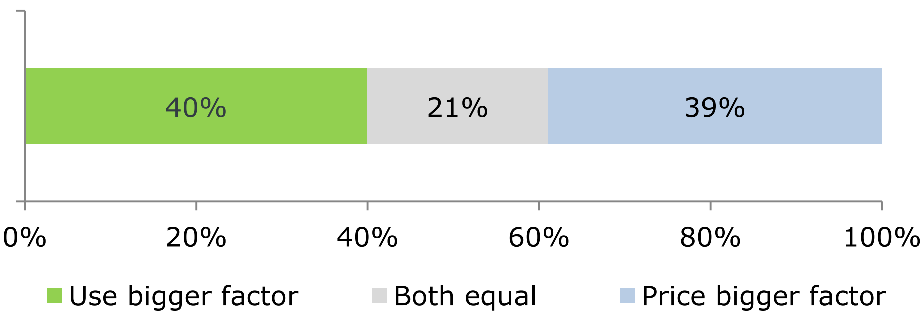
Business



Perceived Influence of Use and Price on Gas Bill

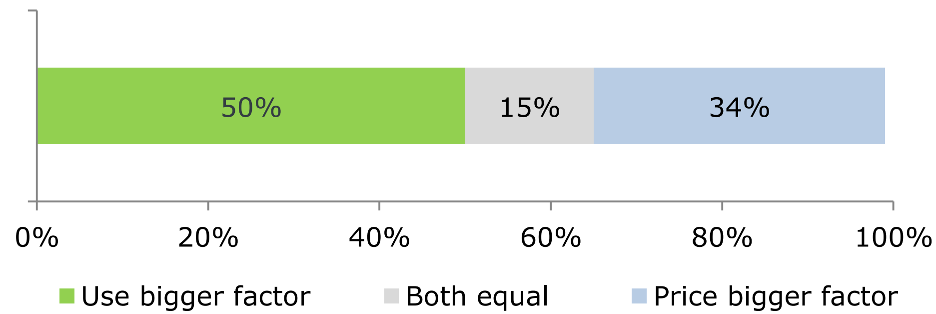
Residential

How are use and price perceived to influence gas bill?



Business

How are use and price perceived to influence gas bill?



SENTIS
measuring what matters

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Appendix D

2012 CUSTOMER FOCUS GROUP RESULTS

Alternatives for Managing Natural Gas Price Volatility - Focus Group Report

Prepared for:

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October 24, 2012

Table of Contents

Executive Summary and Recommendations

The following summarizes the results of eight focus groups (4 with FortisBC residential customers and 4 with FortisBC commercial customers) in which the FortisBC bill was discussed, as well as existing and a series of potential natural gas price volatility management programs[1]. The groups were held in Vancouver and Kelowna from September 24 to 27, 2012. The discussion followed a guide developed with FortisBC representatives. Respondents who attended the discussion were given an incentive for doing so ($75 – residential; $125 – commercial). Given the nature of qualitative research, the results should be considered as directional only[2].

Executive Summary

1. Overall understanding of the FortisBC bill was fair to poor. Few, if any, participants could define the various charges (e.g. delivery, basic, midstream and commodity charges) correctly and confidently. The common complaint was that the number of individual charges and costs on the bill obscures how FortisBC arrives at the total amount. As a result, respondents tended to ignore these charges, looking first at the bottom line amount on the bill and little else.

2. Overall, respondents expected the cost of natural gas to remain stable for at least the next five years. They have heard that significant natural gas reserves exist and that changes in the extraction process have dramatically increased supply and therefore reduced its price.

3. A minority of respondents were aware that FortisBC makes its profits on marking up the delivery cost of natural gas. Most assumed that FortisBC marked up the commodity cost. At the same time, respondents did not understand the midstream cost and were confused that there would be two delivery charges. This heightened level of concern has created some skepticism about the transparency of the charges customers pay.

4. Participants indicated that the bill serves two primary purposes, including: (1) outlining how much is owed, and (2) how much energy was consumed. The current bill focuses mostly on costs.

5. Respondents saw a role for FortisBC to provide mechanisms that might help people budget their natural gas expenses (e.g. the Equal Payment Plan) but they didn't have high expectations for FortisBC to solve these problems.

6. After reviewing the proposed programs, respondents voiced concern that FortisBC was trying to increase its profits with these programs rather than mitigate price volatility. Essentially, people were leery of any premiums for these hedged products.

[1] A description of each product is available in Appendix to this report.
[2] For a full description of the limitations of qualitative research, please see page 8.

More importantly, respondents said that they would have more interest in these hedged products if gas prices were increasing beyond a normal rate (e.g. inflation).

7. Participants said that only one or two such programs were required. Too many programs would cause confusion because they lack a deeper understanding of how they are charged for natural gas making it difficult to determine how these programs would work.

8. Respondents were generally aware of and amenable to the Equal Payment Plan (EPP). If not through FortisBC, they are aware of it through BC Hydro. **To the detriment of the program, some respondents incorrectly assumed that if they enrolled in the program they would not receive any consumption information on their bills.** This is perhaps a communication goal to be pursued in 2013. Overall, EPP was considered a useful tool for new businesses or for households that have stricter budgeting needs.

9. The Customer Choice Program was the least popular of all programs investigated. Respondents were angry at Gas Marketer sales activities and deeply troubled by the idea of being locked into a contract especially if gas prices were declining.

10. When discussing the Price Protect program, respondents failed to make a connection between it and the activities of gas marketers. Still, the remaining fear was that they would be unable to take advantage of savings if the market rate fell below their contracted rate.

11. The Rate Cap program, on the other hand, held the most promise for respondents because it would cap rates at a certain level yet still allow them to take advantage of cost reductions if prices fall.

12. The Rate Protect program was the least popular program because the proposed fund was too complicated and difficult to administer.

Recommendations

1. **Redesign the FortisBC bill to eliminate confusing jargon (i.e., rename or explain terminology when presented) and simplify presentment for improved understanding.**

   Analysis revealed that customers use their bill for knowing how much is owed as much as it is for assessing consumption. The current series of charges (basic, delivery, etc.) is obscuring these fundamental features. Improved terminology, graphic use and overall layout could rectify the problem.

2. **Don't introduce a variety of new volatility mitigation programs.**

   Respondent preference was to simply pay the variable amount on their monthly bills. Although many acknowledged that a new program could help some customers better cope with increased price volatility, they typically stated that this was really the responsibility of the customer rather than FortisBC. Additionally, they found the programs presented as complex and somewhat confusing. Making a choice between the different offers was considered quite difficult. Therefore, FortisBC should provide only one, perhaps two, programs to mitigate price fluctuations. Providing more will increase confusion and therefore skepticism as to why FortisBC is offering such programs in the first place.

3. **The Equal Payment (EPP) and the Rate Cap Programs are likely the best choices to offer.**

   Respondents are familiar with EPP and that makes it easy and comfortable for them to participate. Respondents said that Equal Payment Plan is not a completely accurate description of the program but that it does a good job of ensuring there is no shock in bill amounts. Meanwhile, the Rate Cap program garnered the most interest because it would allow customers to cap their rate and most importantly, should the price of gas fall, take advantage of cost reductions.

Background and Objectives

Background

In the recent past, the natural gas market has experienced decreasing prices as supply exceeds demand. Substantial reserves of shale gas located within North America combined with a global economic downturn have contributed to these reductions. Despite this, it is likely that gas prices will eventually rebound. As part of its July 2011 decision (G-120-11), the BCUC asked FortisBC to review, revise and create ways and means of reducing natural gas price volatility for its customers. This represents the overall intent of this research.

Based on earlier research done in 2005 on the same topic and through other research completed for FortisBC, the most likely people to experience price volatility are residential customers and small to medium-sized enterprises (SME). Traditionally, customers protect themselves from price volatility through various means such as equal payment plans or by using gas marketer services. Such products and services help customers balance the cost of natural gas against the price of natural gas. How well they understand the effectiveness of these solutions or the basis for their existence are topics of speculation.

Objectives

The objectives of this research are about learning how well residential and SME's understand natural gas pricing, what they see as the future of gas pricing, and assess ways and means of reducing the potential shock of pricing volatility.

Specifically, this research will:

- Determine customer tolerance for rate and bill fluctuations and develop a basic profile of those that are most sensitive to such volatility;
- Create an understanding of how different segments (i.e. lower income residents) would evaluate various FortisBC rate options;
- Compare customer opinions and preferences for a hedged product;
- Assess the degree to which customers understand that there is a speculative component to natural gas pricing;
- Learn if FortisBC's quarterly flow-through mechanism has shifted customer assumptions that natural gas prices are, by nature, volatile and therefore making natural gas a less attractive energy option;
- Identify communication barriers that could affect the introduction of products that manage price volatility, especially when it comes to self-funded alternatives; and,
- Assess the preferred adjustment periods for various rate options.

Methodology

This qualitative research focused closely on getting to know how price sensitive customers are, to evaluate their attitudes and opinions regarding the existing market rate, and finally to investigate the level of interest in several different products designed to mitigate gas price volatility.

Detailed Methodology

Considering the comprehensive nature of this project's objectives, eight focus groups were conducted as follows:

Location	Number of Groups	Target Audience
Lower Mainland	2	Residential
	2	Small commercial
Kelowna	2	Residential
	2	Small Commercial

Potential respondents were screened according to a questionnaire created in conjunction with FortisBC's Market Research team and respondents received an incentive ($75-residential/$125-commercial) to attend. We recruited 10 participants for each residential group and 8 for each commercial group. Moreover, Sentis screened respondents based on overall sensitivity to price volatility rather than participation in an equal payment plan. Doing so ensured that FortisBC realized a greater understanding of the price-sensitive market.

Research Limitations

The normal limitations of qualitative research must be kept in mind. Respondents were selected non-randomly and as such, their views cannot be regarded as quantifiable or projectable to any specific population cohort.

The information obtained may be viewed as an indication of existing attitudes but not the extent to which their attitudes are represented in any defined population.

Finally, in-depth interviews are not “unreliable surveys.” Rather, they are idea-generating vehicles where any avenue of information that appears to evoke useful ideas or problem solving suggestions is pursued and reported.

The results from this research should be considered as directional.

Key Findings

1. Fortis Bill Comprehension
2. Price Volatility Mitigation Programs
3. Specific Programs

FortisBC Bill Comprehension

Overall Understanding

Overall understanding of the FortisBC bill was fair to poor. Respondents had difficulties interpreting the various charges on the bill and readily admitted to having difficulty in accurately recounting what each of the charges (e.g. Delivery, Mid-Stream, Commodity, etc.) represented. When asked to define these charges, respondents were typically unsure of their answers. In other words, few participants, if any, could define the various charges correctly and confidently.

The most common, overarching complaint was that the number of individual charges and costs on the bill obscures how FortisBC arrives at the total amount. As a result, respondents had a tendency to ignore these charges opting instead to look first at the bottom line amount and little else.

"Somebody somewhere, some place thought we'd understand this. But we don't."

"This almost seems intentionally confusing."

Moreover, a number of respondents suggested that the definitions of these charges should be printed somewhere on the bill. In fact, this information currently appears on the back of the bill. This means that most people fail to review their bills in any significant detail and as such suggests an overall lack of interest in the topic.

Opinions on Price Stability

For the most part, respondents expected the cost of natural gas to remain generally stable for at least the next five years because they were somewhat aware that significant natural gas reserves have become available and this extra supply has served to lower the overall price.

Only a few respondents said that if natural gas sales to China begin in earnest the result could represent significant increases in its cost.

Unaided Recall

Before respondents received a copy of a FortisBC bill, they were asked what items appeared on it. The most typical responses were:

- The total amount of the bill
- Taxes such as HST and, less often, carbon tax
- Commodity Charge (respondents referred to this as consumption charge)
- The consumption history graph

Aided Recall

Respondents were then presented with a sample bill and asked about its various charges. When specifically asked about each there were as many questions as there were answers. In other words, the bill's charges were creating varying levels of confusion and concern:

> *"I just wish the customer wouldn't be charged when we turn off whatever the gas appliance is for the 6 or 7 months it isn't in use.*

- **Delivery Charges:** Respondents understood but did not like the idea of the basic charge. They compared it to cell phone System Access Fees and complained that even if they did not use any natural gas (e.g. in the summer months) they would still be charged to access natural gas. Many were surprised to know that this fee covers emergency response and call centre service.
- As for the Delivery Charge, many respondents were unaware that this is where FortisBC makes its profit. Most assumed profits were made by marking up the cost of the gas. Many were quite surprised to learn this was not the case.

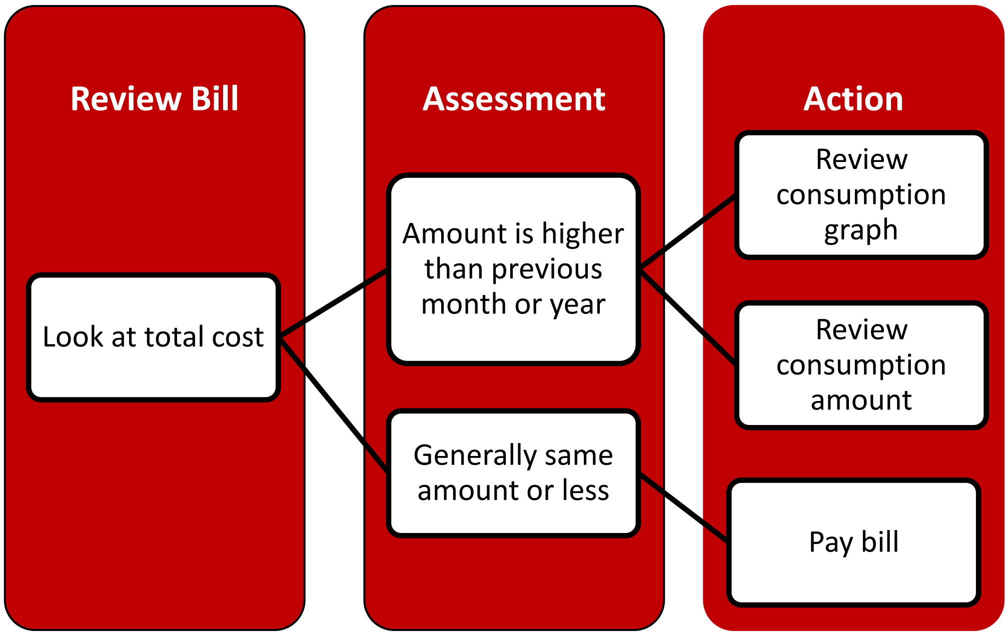
> *"How is transport different from delivery? Now I'm beginning to feel fleeced.""*

- **Commodity Charges:** One of the most fundamental misunderstandings on the bill is the difference between the Delivery Charge and the Midstream Charge. Respondents categorized the term "midstream" as meaningless and likely industry jargon. This caused respondents a great deal of confusion because many assumed that FortisBC is also a resource developer that extracts its own natural gas. For these people, it was unclear why FortisBC would be charging twice on their bill for delivering gas to their homes. They did not realize that there was a cost to bring the gas from gas sellers into the FortisBC grid.

  As mentioned, many respondents assumed that FortisBC makes its profit from the cost of gas itself rather than from the delivery charge.

How the FortisBC Bill is Read

During subsequent analysis of the discussion, it became apparent that the manner in which people go about reviewing their bill has little to do with how charges are levied and more to do with assessment of their own consumption behaviour. Therefore, respondents typically review the bill from the bottom up rather than the top down.



Generally, reading and reviewing the bill follows this process:

1. Look at the "Please Pay" section to determine if the amount ***looks*** similar to either the previous billing period or the same time one year previous.
2. If the amount looks similar, respondents said that they would look no further and simply pay the bill.
3. If respondents noted a discrepancy, they would first go to the consumption graph that shows their consumption history. If that demonstrates a significant difference in amounts, only then will they look for the actual consumption amount. If it generates concern, respondents will assess what might be causing higher gas use (e.g. lifestyle changes or an equipment problem).
4. If analysis proves unexplainable and the increase is relatively high, respondents said that they would be likely to call FortisBC for assistance.

Towards Better Bill Comprehension

Participants had some suggestions on how to improve overall comprehension of their bills.

- Reduce the number of charges listed on the bill. One respondent likened the FortisBC bill to that of a garment price tag that shows how much shipping, warehousing and manufacturing costs went into the final garment price. She said that the information on the FortisBC bill was unhelpful and tended to obscure its total cost.

- Provide better graphics that explain bill features. Respondents clearly liked the consumption graph on their bills because it effectively demonstrates shifts in overall consumption. Respondents spontaneously mentioned and liked the idea of providing a pie chart that explains the percentages of hidden costs in the final cost much like the tax stickers seen on retail gasoline pumps (*right*).

- If the existing variety of charges must remain, respondents sought improved terminology for them. In the current format, the existing terms made the bill very hard to comprehend.

Price Volatility Mitigation Programs

FortisBC's Role in Price Volatility Mitigation

Respondents did not maintain high expectations for FortisBC to provide programs to mitigate price volatility. While they saw a role for FortisBC to provide mechanisms that might help people budget their natural gas expenses (e.g. Equal Payment Plan) they didn't hold an expectation for FortisBC to solve such problems for their customers. As a result, participants were somewhat surprised by FortisBC taking an interest in creating the proposed programs.

Overall Regard for Price Programs

Price Stability

For the most part, participants believed that natural gas prices will remain low at least over the medium-term and therefore interest in all of the these programs was tempered by this supposition. Later, respondents were asked if they would feel differently about these programs if prices were escalating. Respondents quickly said that they would be much more attuned and interested in all of the proposed programs.

> *"Gas prices are historically low. I doubt there will be big upward [movement] in the commodity costs."*

Opinions Did Not Differ Between Business and Residential Respondents

There were no strong differences between the opinions of business and residential respondents on the pricing options. New businesses, with their lower revenues, were as likely as lower income respondents in wanting to minimize gas bill surprises. Moreover, businesses and residential respondents expressed similar reasoning for wanting to maintain energy cost consistency. Those reasons were price shock elimination and budget maintenance.

Suspicion That FortisBC Just Wants to Increase Profits through These Programs

Many of the proposed price mitigation programs were described as requiring the customer to pay a *premium* or a *fee* to participate. Respondents voiced concern that FortisBC was only trying to increase its profits with these programs rather than find ways to mitigate price volatility. They treated references to "premium" with trepidation and suspicion. The moderator had to reassure respondents that such fees and costs would be reasonable. Despite such explanation respondents did remain concerned about the actual amount that these programs would cost.

"In fact, considering that Fortis may well implement profit-increasing plans, I will look to purchase shares in Fortis."

"These programs only benefit Fortis. Not the consumer."

Respondents Preferred Fewer than More Programs

Respondents were presented with a series of options that could be used to mitigate price fluctuations.

Although consumers regularly seek choice, respondents said that only one or two such programs were required because too many would cause confusion. The source of such confusion is their general lack of understanding that surrounds the bill and its workings. Among all the charges on the bill, they can grasp some level of understanding around consumption data. Their primary fear in these programs is that they will lose touch with their consumption and therefore the overall cost of natural gas. As such, these programs can create inconsistencies with energy efficiency and conservation programs.

"[These ideas] *are clear to me but they may be hard to sell to the average person without a lot of explanation."*

"Pay for what I get. Natural gas is cheap and plentiful. I don't want to have to watch the fluctuations and worry about whether I locked in at a good time or fret that I locked in too early or too late. Also I don't like the idea of paying a premium or fee to receive the privilege of possibly saving money or not."

Specific Programs

Paying the Market Rate

By far, most respondents preferred to pay the market rate. Such preference arose out of a need to see their consumption and make simple, logical connections between that and the cost on the bill. As mentioned earlier, participants had trouble interpreting basic bill details and therefore they feared that a price mitigation program would prevent direct connections between consumption and cost.

> *"I prefer the clarity of paying as you go. I can budget myself (overestimate gas costs) and put this amount away in my own rainy day fund."*

> *"I would prefer to pay the market price so you don't get a surprise at the end of the year."*

Equal Payment Program (EPP)

Respondents were generally amenable to the program mostly out of familiarity and some participants were already enrolled in the program. Although some respondents were unaware that FortisBC offers it, they were familiar with the concept through other utilities, most notably, BC Hydro.

Most considered EPP as a useful household budgeting tool, particularly for new businesses and those households where sticking to a budget is important. Therefore, the overarching benefit was reliable prediction of monthly energy expenses.

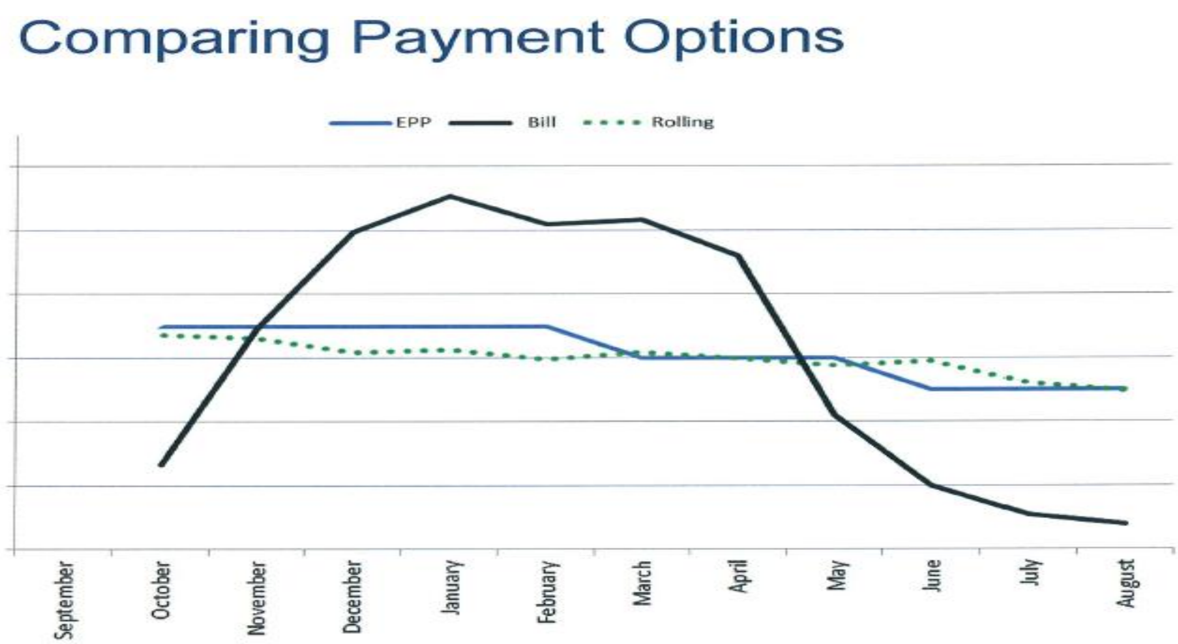
Unfortunately, some respondents assumed that if they enrolled in the program they would no longer see their consumption data. Once addressed, program approval by these respondents significantly improved. Ultimately, the fear is that a consumption problem (e.g. a leak) would go unnoticed.

> *"I like the idea but then I wouldn't be able to see any of my* [consumption} *history."*

Also, respondents noted that while they were comfortable and familiar with the Equal Payment Plan program name, it did not truly reflect the nature of the program. In EPP, payments are, in fact, not equal because the name does not reflect the quarterly "true-up."

A Rolling Average

While discussing this program, respondents were introduced to the idea of using a 13-month rolling average instead of a quarterly "true-up" of their bill. Although the reaction was favourable, some participants had significant difficulty understanding the concept of a rolling average. The net result was that after some level of explanation (that usually involved a number of follow-up questions) respondents liked the idea. If FortisBC were to offer a rolling average, the difficulty would lie not in selling the end-result but rather in explaining the concept of a rolling average.



Customer Choice Program

Of all the programs, this one was the least popular. Respondents had very angry opinions of gas marketers, did not trust them and did not want to have anything to do with them. The overarching reason was that they feared that gas marketers would use their lack of understanding about natural gas charges against them and lock them into high rates for a long term. Specific problems they pointed out for such mistrust were:

- aggressive marketing techniques;
- unscrupulous contracts full of fine print;
- being locked in at high rates; and,
- losing the ability to take advantage of cheaper rates when natural gas prices fall.

When respondents were asked to separate the marketing practices with the concept of dealing with an alternate marketer, opinion remained unfavourable because of the last point on the list above.

"It isn't worth risking paying a higher rate for years as the chance of the price rising and falling is high. It's not worth the risk."

Price Protect

Essentially, the Price Protect option offers a similar program comparable to those offered by the gas marketers. That said, respondents failed to make a direct connection with Customer Choice and while most did not like the idea of the program, they did so without the level of anger with which they discussed gas marketers.

In this instance, the critical downside of the program was a fear of being unable to take advantage of lower rates after a volatility period had passed. That said, respondents said that such a program would be useful in times of rapidly increasing gas commodity prices and that the term of the contract is critically important. Most agreed that a one-year term would be the most they would tolerate.

"If prices drop, you can treat it as savings and put it into something else."

Rate Cap

Of all the proposed new programs, Rate Cap held the most promise for respondents because it offers the ability to take advantage of lower gas prices when they occur. In other words, respondent fears of higher prices were appeased because they would eventually take advantage of lower rates when prices come down.

With the assurance that additional costs would be reasonable, respondents chose this program behind "Paying the Market Rate" and the "Equal Payment Plan."

"If I were to go with a program, I would say Rate Cap but I always think a program designed to save you money will always cost you in the end."

Rate Protect

As one of the least popular programs, respondents considered it:

- too complicated to understand;
- requiring auditing to ensure that funds are not being misused;
- worrisome as to whether or not enrollees would receive interest on the funds they contribute; and
- fostered concern that if they move, they would not be able to get the money back that they paid into the fund.

One additional concern was that the program takes the FortisBC brand out of the familiar territory of being an energy provided into that of banker; a role that participants did feel that FortisBC should not take on.

"What percentage return [will I get] on the money I put in? Would it keep up with inflation?"

"Fortis takes the return on this investment into their overall profit."

Appendix

1. Recruitment Screeners
2. Discussion Guides
3. Program Descriptions
4. Respondent Workbook

FortisBC – Focus Group Screener
Participant Research: Price Volatility Focus Groups - RESIDENTIAL

Date:	**Interviewer:**	**ID#:**
Respondent Name:	**Gender:**	
Address:		
City:	**Prov.: B.C.**	**Postal:**
Daytime Phone:	**Evening Phone:**	
E-Mail / Fax:		

RECRUIT 10 FOR 8 TO SHOW
Try for a mix of Lower Mainland cities (listed on sample)

Vancouver **Date: September 24, 2012** **Vancouver Focus** **1156 Hornby Street, Mezzanine Level** **Vancouver, BC** **Phone: (604) 682-4292**	Group 1 – Residential - 5:30pm
	Group 2 – Residential - 7:30pm
Date: September 26, 2012 **Delta Grand Hotel** **1310 Water Street** **Kelowna** **Phone: (250) 763-4500**	Group 5 – Residential - 5:30PM
	Group 6 – Residential - 7:30PM

Please follow these guidelines when recruiting for focus groups:

- Complete recruiting grid and send an update via email gerry.keane@participantresearch.ca the next day.
- Please call, confirm and re-screen ALL respondents a day or two before the focus group.

INTRODUCTION

Hello my name is _____________, with Participant Research an independent marketing research firm. We are conducting market research in your area regarding FortisBC [DATE: September X] for this study. May I please speak to [**NAME ON LIST**]?

We are very interested in speaking with you to learn about customer's tolerance for and attitudes towards natural gas price fluctuations. Therefore, we are inviting a select group to participate in an informal discussion, the results of which will be used to develop strategies to reduce the risk associated with future natural gas price fluctuations.

Are you the person who would be either responsible or jointly responsible for making decisions about energy choices in your home?

Yes **CONTINUE**
No **ASK TO SPEAK TO THAT PERSON AND RESTART RECRUITMENT SCREENER, OTHERWISE THANK AND TERMINATE**

If you attend one of the sessions you will receive a cash honorarium of $75 for your time. To ensure we get the right individuals, I will need to ask you a few questions. Please be assured that I am NOT trying to sell you anything and no one from FortisBC will contact you after the focus group. We are just interested in hearing your opinions.

[**IF NECESSARY:** The Group will only last 2 hours and participants will simply exchange ideas and opinions with a group of about 7 others.

The groups will be held on September XX in the evening, is this something you would be interested in?

Yes **CONTINUE**
No **THANK AND TERMINATE**

DISABILITY

Sometimes, participants in these groups are asked to watch or listen to a video or sound recording. Is there anything that would prevent you from participating in this activity?

Yes – HEARING IMPARED OK WITH HEARING AIDS. IF VISUALLY IMPARED ASK IF THEY WOULD BE ABLE TO SEE A TELEVISION SCREEN FROM A REASONABLE DISTANCE. IF NOT, THANK AND TERMINATE CAREFULLY.

No – CONTINUE

CONTACT if needed:

Please use a RECRUITMENT telephone number to take cancellations.

Participant Research: **Gerry Keane 604-339-8620 (Evening & Weekend calls OK)**
FortisBC : **Roy Mokha 778-578-8095 (FOR RESEARCH VERIFICATION ONLY)**

BACKGROUND

1. Do you or does any member of your household or immediate family work or have ever worked in the following? **[READ LIST]**

	Yes
A) Marketing or market research	☐
B) Advertising, communications or public relations	☐
C) Media (including newspapers, magazines, radio, TV, etc.)	☐
D) FortisBC, BC Hydro or any other energy provider and its affiliates	☐
D) An environmental agency, advocate or government department dealing with energy or the environment	☐

IF "YES" TO A, B, C THANK & TERMINATE

1. Are you individually or jointly responsible for paying your FortisBC gas bill?

Yes **CONTINUE**
No **THANK AND TERMINATE**
Don't Know **THANK AND TERMINATE**

2. Which one of the following age categories do you fit into?

18-21 **THANK AND TERMINATE**
22-35
36-45
46-59
60 or more **THANK AND TERMINATE**

OBTAIN A GOOD MIX OF AGES BETWEEN 21 AND 55

3. Gender **OBSERVE – RECRUIT 50% FEMALE AND 50% MALE SPLIT FOR EACH GROUP**

Male
Female

4. How positive or negative do you feel about the following companies?

	Very Positive	Somewhat Positive	Somewhat Negative	Very Negative
BC Hydro				
FortisBC				

THANK AND TERMINATE IF "FortisBC" = Very Negative
MAXIMUM OF TWO PER GROUP = "Somewhat Negative"

4. How much do you agree or disagree with the following statements?

I would pay a little more money each month if I knew that my utility charges would not fluctuate frequently.

Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
CONTINUE	**CONTINUE**	**CONTINUE**	**MAX. OF 1 PER GROUP**

5. Imagine you're setting next year's monthly household budget. Assuming gas prices would increase by 25%, how much would this increase cause you to change your behaviour (such as turning down your thermostat or cutting back spending in other areas of your household budget)

Very much	Somewhat	A little	Not at all
Continue	**Continue**	**CONTINUE**	**MAX. OF 1 PER GROUP**

6. What kind of home do you live in? **READ LIST**

High-rise or low-rise apartment or condominium	**CONTINUE**
Single detached home	**CONTINUE**
Duplex, triplex	**CONTINUE**
Town or Row home	**CONTINUE**
Mobile home	**CONTINUE**

7. What is the main fuel you use to heat your home?

Natural gas	**CONTINUE**
Electricity	**THANK AND TERMINATE**
Other	**THANK AND TERMINATE**

8. Do you own or rent your home?

Own	**CONTINUE**
Rent	**MAXIMUM OF 3 RESPONDENTS**
Other	**THANK AND TERMINATE**

9. Do you purchase your gas through a gas marketer?

Yes	**RECRUIT 2**
No	**CONTINUE**
Don't know	**ASSUME ANSWER IS "NO" AND CONTINUE**

10. What kinds of natural gas appliances do you have in your home? (**CHECK ALL THAT APPLY**)

Gas furnace
Gas fireplace
Gas stove/cooktop/range
Gas water heater (standard and instantaneous)
Gas Bar-B-Q
Gas clothes dryer
Gas boiler (radiant/in-floor heat)

Finally, we have a few questions just for clarification purposes.

11. What is your employment status?

Unemployed	**THANK AND TERMINATE**
Homemaker	**MAXIMUM OF ONE PER GROUP**
Full/Part time student	**THANK AND TERMINATE**
Part-time employed	**MAXIMUM 2 PER GROUP**
Retired	**CONTINUE**
Full-time employed	**CONTINUE**

12. What is your occupation or job function?

IF ENERGY RELATED IN ANY WAY, THANK AND TERMINATE

13. What was the household income for all members of your household in 2009, before taxes?

Under $25,000	**CONTINUE**
$25,000 to less than $75,000	**CONTINUE**
$76,000 to less than $100,000	**CONTINUE**
$100,000 or more	**CONTINUE**

AIM FOR A GOOD CROSS SECTION OF INCOMES

14. What is the last level of formal education that you have completed?

Some High School	**THANK AND TERMINATE**
Completed High School	**THANK AND TERMINATE**
Some Community College/Technical School	**CONTINUE**
Completed Community College/Technical School	**CONTINUE**
Some University	**CONTINUE**
Completed University	**CONTINUE**
DK/REF	**THANK AND TERMINATE**

RECRUIT A MIX OF EDUCATION LEVELS: NO HARD QUOTAS

15. What language did you learn to speak as a child and still speak today?

South Asian (Hindi, Urdu)
Chinese (Mandarin or Cantonese)
Other

OBTAIN AT LEAST ONE SOUTH ASIAN AND CHINESE PER GROUP

16. Have you ever participated in a discussion group for research purposes for which you were paid for your time?

Yes	**CONTINUE**
No	**SKIP TO Q17**
DK/REF	**SKIP TO Q17**

17. When was the last time that you participated in one of these groups?

Within the past 6 months	**THANK AND TERMINATE**
6 months to a year	**CONTINUE**
More than a year ago	**CONTINUE**

18. What are the topics or areas you have discussed in focus groups?

____

IF ENERGY SERVICES THANK AND TERMINATE

ARTICULATION

17. I have one last fun question for you; be as creative as you can: If you were to be on the cover of any magazine, which magazine would it be and what would the caption under your picture say?

____

____

ALL MUST SPEAK CLEAR ENGLISH, NO OVERLY-HEAVY ACCENTS. ALL MUST BE ABLE AND WILLING TO ANSWER THIS QUESTION CLEARLY AND EASILY. IF NOT THANK AND TERMINATE.

INVITATION

As mentioned earlier, we are inviting a group of people such as you to participate in a round table discussion regarding FortisBC. This discussion is held for research purposes only; we would very much like your insight and opinions.

Let me assure you that absolutely no attempt will be made to sell you any types of products or services. We'd just like to hear your honest opinions. The group will be relaxed and informal, and you will simply be involved in an exchange of ideas and opinions with a group of about seven others like you.

The discussion will be held at **[CHECK MATRIX BELOW]** on **[CHECK MATRIX BELOW]**. It will last approximately no longer than two hours and refreshments will be served. At the conclusion of the discussion, we will be pleased to present you with $75 in appreciation of your time and opinions. Would you be interested in participating in this research project?

Yes **[CHECK APPROPRIATE GROUP AND RECRUIT]**

No **[THANK & TERMINATE]**

Vancouver **Date: TBD** **Justason Research** **1156 Hornby Street, Mezzanine Level** **Vancouver, BC** **Phone: (604) 682-4292**
Group 1 – 5:30pm
Group 2 – 7:30pm

[READ TO ALL:]

You will need to bring picture ID to the groups.

THERE WILL BE VISUALS IN THE GROUPS. IF YOU REGULARLY WEAR READING GLASSES, PLEASE BE SURE TO BRING THEM WITH YOU AS WELL.

We'll also be sending you an e-mail to confirm this invitation, along with a map to the facility if you need it. May I please have the correct spelling of your name and an e-mail address? **[RECORD ON FRONT PAGE]** For this project, it is very important that we are able to count on your attendance. **If, for any reason, you find yourself unable to join us, please call us at *INSERT RECRUITER PHONE NUMBER HERE* as soon as possible. This will, hopefully, enable us to find a replacement for you.**

FortisBC – Focus Group Screener
Participant Research: Price Volatility Focus Groups - COMMERCIAL

Date:	**Interviewer:**	**ID#:**
Respondent Name:		**Gender:**
Address:		
City:	**Prov.: B.C.**	**Postal:**
Daytime Phone:	**Evening Phone:**	
E-Mail / Fax:		

RECRUIT 10 FOR 8 TO SHOW
Try for a mix of Lower Mainland cities (listed on sample)

Vancouver **Date: September 25, 2012** **Vancouver Focus** **1156 Hornby Street, Mezzanine Level** **Vancouver, BC** **Phone: (604) 682-4292**	Group 3 – Business – 8:00AM
	Group 4 – Business – 5:30PM
Date: September 27 **Delta Grand Hotel** **1310 Water Street** **Kelowna** **Phone: (250) 763-4500**	Group 7 – Business – 8:00AM
	Group 8 – Business - 5:30PM

Please follow these guidelines when recruiting for focus groups:

- Complete recruiting grid and send an update via email gerry.keane@participantresearch.ca the next day.
- Please call, confirm and re-screen ALL respondents a day or two before the focus group.

INTRODUCTION

Hello my name is _____________, with Participant Research an independent marketing research firm. We are conducting market research in your area regarding FortisBC [DATE: September X] for this study. May I please speak to [**NAME ON LIST**]?

We are very interested in speaking with you to learn about customer's tolerance for and attitudes towards natural gas price fluctuations. Therefore, we are inviting a select group of business people to participate in an informal discussion, the results of which will be used to develop strategies to reduce the risk associated with future natural gas price fluctuations.

Are you the person who has access to the monthly natural gas bill and can make decisions on energy use? **(THIS PERSON COULD BE DIFFERENT FROM THE PERSON WHO SIMPLY PAYS THE BILL)**

Yes **CONTINUE**
No **ASK TO SPEAK TO THAT PERSON AND RESTART RECRUITMENT SCREENER, OTHERWISE THANK AND TERMINATE**

If you attend one of the sessions, you will receive a cash honorarium of $125 for your time. To ensure we get the right individuals, I will need to ask you a few questions. Please be assured that I am NOT trying to sell you anything and no one from FortisBC will contact you after the focus group. We are just interested in hearing your opinions.

[**IF NECESSARY:** The Group will only last 2 hours and participants will simply exchange ideas and opinions with a group of about 7 with similar backgrounds to yours.

The groups will be held on September XX, is this something you would be interested in?

Yes **CONTINUE**
No **THANK AND TERMINATE**

DISABILITY

Sometimes, participants in these groups are asked to watch or listen to a video or sound recording. Is there anything that would prevent you from participating in this activity?

Yes – HEARING IMPARED OK WITH HEARING AIDS. IF VISUALLY IMPARED ASK IF THEY WOULD BE ABLE TO SEE A TELEVISION SCREEN FROM A REASONABLE DISTANCE. IF NOT, THANK AND TERMINATE CAREFULLY.

No – CONTINUE

CONTACT if needed:

Please use a RECRUITMENT telephone number to take cancellations.

Participant Research: Gerry Keane 604-339-8620 (Evening & Weekend calls OK)
FortisBC : Roy Mokha 778-578-8095 (FOR RESEARCH VERIFICATION ONLY)

BACKGROUND

1. Do you or does any member of your household or immediate family work or have ever worked in the following? **[READ LIST]**

	Yes
A) Marketing or market research	☐
B) Advertising, communications or public relations	☐
C) Media (including newspapers, magazines, radio, TV, etc.)	☐
D) FortisBC, BC Hydro or any other energy provider and its affiliates	☐
D) An environmental agency, advocate or government department dealing with energy or the environment	☐

IF "YES" TO A, B, C THANK & TERMINATE

2. Are you individually or jointly responsible for paying your FortisBC gas bill?

Yes **CONTINUE**
No **THANK AND TERMINATE**
Don't Know **THANK AND TERMINATE**

OBTAIN A GOOD MIX OF AGES BETWEEN 21 AND 55

3. Gender **OBSERVE – AIM FOR A GOOD MIX**

Male
Female

4. How positive or negative do you feel about the following companies?

	Very Positive	Somewhat Positive	Somewhat Negative	Very Negative
BC Hydro				
FortisBC				

THANK AND TERMINATE IF "FortisBC" = Very Negative
MAXIMUM OF TWO PER GROUP = "Somewhat Negative"

5. How much do you agree or disagree with the following statements?

I would pay a little more money each month if I knew that my utility charges would not fluctuate frequently.

Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
CONTINUE	**CONTINUE**	**CONTINUE**	**MAX OF 1 PER GROUP**

6. Imagine you're setting the budget for next year's operations. Assuming gas prices would increase by 25%, how much would this increase cause you to change your behaviour (such as turning down your thermostat or cutting back spending in other business areas)

Very much	Somewhat	A little	Not at all
CONTINUE	**CONTINUE**	**CONTINUE**	**MAX OF 1 PER GROUP**

7. What kind of building does your business occupy? If you have more than one location, please think about the location that consumes the most natural gas. **READ LIST**

High-rise or low-rise office building	**CONTINUE**
Retail Storefront	**CONTINUE**
Warehouse/Light industrial	**CONTINUE**
Institutional (hospital/school/residence)	**CONTINUE**
OTHER (specify):	**CONTINUE**

8. What is the main fuel you use to heat your business?

Natural gas	**CONTINUE**
Electricity	**THANK AND TERMINATE**
Other	**THANK AND TERMINATE**

9. Do you own or rent your location? If you have more than one location, please think about the location that consumes the most natural gas.

Own	**CONTINUE**
Rent	**MAXIMUM OF HALF RESPONDENTS**
Other	**THANK AND TERMINATE**

10. Do you purchase your gas through an independent gas marketer?

Yes	**RECRUIT 2**
No	**CONTINUE**
Don't know	**ASSUME ANSWER IS "NO" AND CONTINUE**

11. What kinds of natural gas appliances do you have in your business? (**CHECK ALL THAT APPLY**)

Gas furnace
Gas fireplace
Gas stove/cooktop/range/grills
Gas water heater (standard and instantaneous)
Gas boiler

Finally, we have a few questions just for clarification purposes.

12. What is your occupation or job function?

---

13. How many square feet is your business location? If you have more than one location, please think about the location that consumes the most natural gas.

Less than 500	**CONTINUE**
500 to 1500	**CONTINUE**
1501 to 5000	**CONTINUE**
More than 5000	**CONTINUE**

AIM FOR A MIX OF SIZES

14. Have you ever participated in a discussion group for research purposes for which you were paid for your time?

Yes	**CONTINUE**
No	**SKIP TO Q17**
DK/REF	**SKIP TO Q17**

15. When was the last time that you participated in one of these groups?

Within the past 6 months	**THANK AND TERMINATE**
6 months to a year	**CONTINUE**
More than a year ago	**CONTINUE**

16. What are the topics or areas you have discussed in focus groups?

____

IF ENERGY SERVICES THANK AND TERMINATE

ARTICLATION

17. I have one last fun question for you; be as creative as you can: If you were to be on the cover of any magazine, which magazine would it be and what would the caption under your picture say?

____

____

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INVITATION

As mentioned earlier, we are inviting a group of people such as you to participate in a round table discussion regarding FortisBC. This discussion is held for research purposes only; we would very much like your insight and opinions.

Let me assure you that absolutely no attempt will be made to sell you any types of products or services. We'd just like to hear your honest opinions. The group will be relaxed and informal, and you will simply be involved in an exchange of ideas and opinions with about seven others like you.

The discussion will be held at **[CHECK MATRIX BELOW]** on **[CHECK MATRIX BELOW]**. It will last approximately no longer than two hours and refreshments will be served. At the conclusion of the discussion, we will be pleased to present you with $125 in appreciation of your time and opinions. Would you be interested in participating in this research project?

Yes **[CHECK APPROPRIATE GROUP AND RECRUIT]**
No **[THANK & TERMINATE]**

Vancouver **Date: TBD** **Justason Research** **1156 Hornby Street, Mezzanine Level** **Vancouver, BC** **Phone: (604) 682-4292**
Group 1 – 8:00AM
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We'll also be sending you an e-mail to confirm this invitation, along with a map to the facility if you need it. May I please have the correct spelling of your name and an e-mail address? **[RECORD ON FRONT PAGE]** For this project, it is very important that we are able to count on your attendance. **If, for any reason, you find yourself unable to join us, please call us at *INSERT RECRUITER PHONE NUMBER HERE* as soon as possible. This will, hopefully, enable us to find a replacement for you.**

FortisBC
Price Volatility Focus Groups - Residential
Discussion Guide – V2
September 19, 2012

Research Objectives

- Create a detailed understanding of how well consumers comprehend natural gas pricing, bill components and rates as well as their opinions on the future cost of natural gas
- Determine customer tolerance for rate and bill fluctuations and develop a basic customer profile of those who are most sensitive to such volatility
- Learn if FortisBC's quarterly flow-through mechanism has shifted customer assumptions that natural gas prices are, by nature, volatile and therefore making natural gas a less attractive energy option
- Identify communication barriers that could affect the introduction of products that reduce price volatility, especially when it comes to self-funded alternatives
- Assess the preferred adjustment periods and opinions of various rate options
- Assess awareness, use and understanding of the Equal Payment Plan and the Customer Choice Program.

Discussion Guide

1. Introduction
   a. Introduction of moderator, facilities and discussion ground rules
   b. Round table introduction of participants

2. Warm-up
   a. When I say "price fluctuations" what kinds of things come to mind? What products and services are most likely to experience fluctuations? Least likely?
   b. What kinds of things cause prices to fluctuate? **Prompts**: Weather, Economy, World Events, Changes in products or transportation costs; profit motives.

3. Gas Bill Overview
   a. Tell me about your natural gas bill. Is it easy or hard to understand? Which parts?
   b. The Fortis bill is divided between Commodity Charges and Delivery Charges. What are those items? What do they mean? Which charges are most likely to fluctuate? Why?
   c. In all these charges, where does FortisBC make its profit?

4. Understanding the Gas Bill

a. *Moderator distributes focus group workbook while explaining its purpose of catching thoughts before the discussion. Working alone respondents fill out the first section of the book on understanding their gas bills.*

b. How well do you feel that you understand your FortisBC bill in general? Which parts are most difficult?
   i. Prompts: Delivery charges; Commodity charges.
   ii. How clear or confusing is it to have your bill separated like this? Explain fully.

c. Using the workbook, the moderator goes through Basic, Delivery Charges as well as midstream charges and cost of gas charges. For each, prompting for:
   i. Before you read this book, what did you believe that charge was for?
   ii. Does it make sense to break out this item on your bill?
   iii. Why would FortisBC decide to break it out that way?
   iv. How important is it to you to have these charges broken down this way?
   v. Which of these charges are most/least likely to fluctuate?

5. Price Fluctuations

a. How important is it for FortisBC to try to control price fluctuations? Why should it be important?

b. Are there any programs out there that accomplish this task? What are they? Are they helpful or a hindrance?

c. How frequently does FortisBC adjust prices? How frequently *should* they adjust prices?

6. Fluctuation Mitigation Programs

a. *Moderator directs respondents to complete the rest of the workbook while explaining its purpose of catching thoughts before the discussion. Working alone respondents fill out the second section of the book.*

b. Going through each program individually, probe fully for understanding of each, preferences, likes and dislikes

c. Prompts:
   i. Does the program make intuitive sense?
   ii. Ease of understanding
   iii. What makes it difficult to understand (specific aspects)?
   iv. How effective would this program be at protecting you from fluctuations? **Probe for EPP only**: What if the "true-up" was based on a rolling average (i.e. a daily rolling average of historical and current costs plus an adjustment factor?
   v. To help people understand the program better, what are the key themes that FortisBC needs to make known?

d. *For the Customer Choice Program*: Who would/would not sign up for the Customer Choice Program? Why is that? Prompts:
   i. Protection against increasing rates; or,
   ii. Prices are too high already
   iii. Not worried about increasing gas costs

iv. Reduction in variability/fluctuation
v. Marketers offer better rates
vi. Just rather deal with a marketer/prefer to deal with FortisBC/Don't trust marketers
vii. Over the long run, it's always cheaper to go with a variable rate
viii. FortisBC doesn't offer such a program

e. Which program would you sign up for if rates were more volatile or higher than they are right now?

7. Summary

a. Moderator has respondents review the various programs one last time and choose their favourite and next favourite.

b. Working as a group, respondents select the best program and the least favoured program. Moderator uses a flip-chart to highlight the pros and cons of each.

8. Close

FortisBC
Price Volatility Focus Groups - Commercial
Discussion Guide – V2
September 19, 2012

Research Objectives

- Create a detailed understanding of how well business customers comprehend natural gas pricing, bill components and rates as well as their opinions on the future cost of natural gas
- Determine customer tolerance for rate and bill fluctuations and develop a basic profile of those who are most sensitive to such volatility
- Learn if FortisBC's quarterly flow-through mechanism has shifted customer assumptions that natural gas prices are, by nature, volatile and therefore making natural gas a less attractive energy option
- Identify communication barriers that could affect the introduction of products that reduce price volatility, especially when it comes to self-funded alternatives especially for business customers
- Assess the preferred adjustment periods and opinions of various rate options
- Assess awareness, use and understanding of the Equal Payment Plan and the Customer Choice Program.

Discussion Guide

1. Introduction
   a. Introduction of moderator, facilities and discussion ground rules
   b. Round table introduction of participants; the type of business each represents and their role within it.

2. Warm-up
   a. When I say "price fluctuations" what kinds of things come to mind? What products and services are most likely to experience fluctuations? Least likely?
   b. What kinds of things cause prices to fluctuate? **Prompts**: Weather, Economy, World Events, Changes in products or transportation costs; profit motives.

3. Gas Bill Overview
   a. Tell me about your natural gas bill. Is it easy or hard to understand? Which parts?
   b. The Fortis bill is divided between Commodity Charges and Delivery Charges. What are those items? What do they mean? Which charges are most likely to fluctuate? Why?
   c. In all these charges, where do you think FortisBC make its profit?

4. Understanding the Gas Bill

a. *Moderator distributes focus group workbook while explaining its purpose of catching thoughts before the discussion. Working alone respondents fill out the first section of the book on understanding their gas bills.*

b. How well do you feel that you understand your FortisBC bill in general? Which parts are most difficult?

    i. Prompts: Delivery charges; Commodity charges.

    ii. How clear or confusing is it to have your bill separated like this? Explain fully.

c. Using the workbook, the moderator goes through Basic, Delivery Charges as well as midstream charges and cost of gas charges. For each, prompting for:

    i. Before you read this book, what did you believe those charges were for?

    ii. Does it make sense to break out this item on your bill?

    iii. Why would FortisBC decide to break it out that way?

    iv. How important is it to you to have these charges broken down this way?

    v. Which of these charges are most/least likely to fluctuate? Is there a seasonal nature to your business that affects consumption? How?

5. Price Fluctuations

a. How important is it for FortisBC to try to control price fluctuations? Why should it be important?

b. Are there any programs out there that accomplish this task? What are they? Are they helpful or a hindrance?

c. How frequently does FortisBC adjust prices? How frequently *should* they adjust prices?

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c. Prompts:

    i. Does the program make intuitive sense?

    ii. Ease of understanding

    iii. What makes it difficult to understand (specific aspects)?

    iv. How effective would this program be at protecting you from fluctuations? **Probe for EPP only**: What if the "true-up" was based on a rolling average (i.e. a daily rolling average of historical and current costs plus an adjustment factor?

    v. To help people understand the program better, what are the key themes that FortisBC needs to make known?

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    i. Protection against increasing rates; or,

    ii. Prices are too high already

iii. Not worried about increasing gas costs
iv. Reduction in variability/fluctuation
v. Marketers offer better rates
vi. Just rather deal with a marketer/prefer to deal with FortisBC/Don't trust marketers
vii. Over the long run, it's always cheaper to go with a variable rate
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e. Which program would you sign up for if rates were more volatile or higher than they are right now?

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b. Working as a group, respondents select the best program and the least favoured program. Moderator uses a flip chart to highlight the pros and cons of each.

8. Close

FortisBC Focus Groups Workbook

September: 24 25 26 27

Time:__________

Typical residential FortisBC natural gas bill.

FORTIS BC

Name: ANNIE CUSTOMER
Service address: 12345 ANY STREET
VANCOUVER

Rate class: Residential
Billing date: July 3, 2012

NATURAL GAS

Customer Service: 1-888-224-2710
7 am - 8 pm Mon - Fri, 9 am - 5 pm Sat
fortisbc.com

Account number	Due date	Amount due	Amount paid
555555	July 24, 2012	$57.54	

Previous bill	60.16	
Less payment - Thank you	60.16 CR	
Balance from previous bill		0.00
Delivery charges		
Basic charge (32 days at 0.3890 per day)	12.45	
Delivery (4.6 GJ at 3.375 GJ)	15.53	
		27.98**
Commodity charges		
Midstream (4.6 GJ at 1.365 per GJ)	6.28	
Cost of gas (4.6 GJ at 2.977 per GJ)	13.69	
		19.97**
Other charges and taxes		
Carbon Tax (4.6 GJ at 1.4898 per GJ)		6.85**
HST (12% of * amounts)		6.58
Residential Energy Credit (7% of * amounts)		3.84CR
Please pay		**$57.54**

Gas usage calculation (Meter RCZ928229)

Present reading	Previous reading	Conversion factor	Gas used in gigajoules (GJ)
July 3 '12	June 1 '12		
44,682	44,560 Est	0.0377178	4.6

Point of Delivery: 622258

Comparison to previous year

Billing period	Number of days billed	Average daily temp.	Average daily usage GJ	Total billing period usage GJ
July '12	32	16°C	0.14	4.6
July '11	30	15°C	0.09	2.7

Sample

NATURAL GAS

FORTIS BC

Account number	Due date	Amount due	Amount paid
555555	July 24, 2012	$57.54	

ANNIE CUSTOMER
12345 ANY STREET
VANCOUVER, BC V3E 2R7

00 000 459535 0 00008900 5

How well do you understand the difference between what the **Delivery charge** is and what the **Commodity charge** is?

Do not understand at all				Understand extremely well
1	2	3	4	5

How clear or confusing is it to have your natural gas bill separated by **Delivery** and **Commodity** charges?

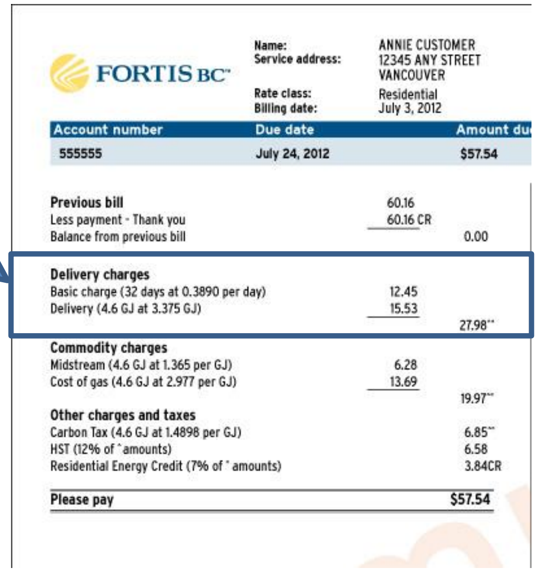
Very confusing				Very clear
1	2	3	4	5

Basic Charge

Under the category of Delivery charges, you will see a **Basic charge**, which is described below.

Basic charge

- Same fee every day of the billing period regardless of gas used ($0.3890 per day)
- Covers the cost of items such as emergency response, call centre service and meter reading



FORTIS BC

Name: ANNIE CUSTOMER
Service address: 12345 ANY STREET VANCOUVER
Rate class: Residential
Billing date: July 3, 2012

Account number	Due date	Amount du
555555	July 24, 2012	$57.54

Previous bill	60.16	
Less payment - Thank you	60.16 CR	
Balance from previous bill		0.00
Delivery charges		
Basic charge (32 days at 0.3890 per day)	12.45	
Delivery (4.6 GJ at 3.375 GJ)	15.53	
		27.98**
Commodity charges		
Midstream (4.6 GJ at 1.365 per GJ)	6.28	
Cost of gas (4.6 GJ at 2.977 per GJ)	13.69	
		19.97**
Other charges and taxes		
Carbon Tax (4.6 GJ at 1.4898 per GJ)		6.85**
HST (12% of * amounts)		6.58
Residential Energy Credit (7% of * amounts)		3.84CR
Please pay		**$57.54**

Before you read the above description, were you aware of what the **Basic** charge covers?

Yes, aware
No, not aware

Based on the description above, how well do you understand what this charge covers?

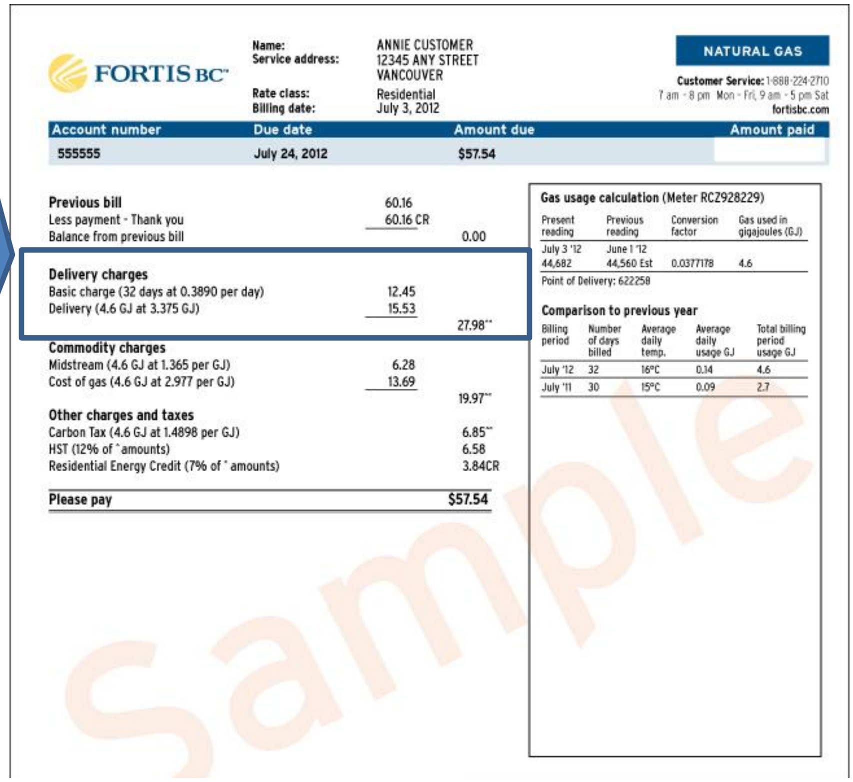
Do not understand at all				Understand extremely well
1	2	3	4	5

Delivery Charge

Still looking under Delivery charges, you will also see a charge for **Delivery**. See the description below.

Delivery

- Cost of delivering the gas through the FortisBC pipeline system to your home or business
- Calculated on a per unit of energy basis (Gigajoule or GJ)
- About one GJ warms a typical house on a cold winter's day
- You are charged for the energy used, so we multiply your monthly consumption (4.6 GJ) by the Delivery charge per unit of energy ($3. 375/GJ).



FORTIS BC

Name: ANNIE CUSTOMER
Service address: 12345 ANY STREET VANCOUVER
Rate class: Residential
Billing date: July 3, 2012

NATURAL GAS

Customer Service: 1-888-224-2710
7 am - 8 pm Mon - Fri, 9 am - 5 pm Sat
fortisbc.com

Account number	Due date	Amount due	Amount paid
555555	July 24, 2012	$57.54	

Previous bill	60.16	
Less payment - Thank you	60.16 CR	
Balance from previous bill		0.00
Delivery charges		
Basic charge (32 days at 0.3890 per day)	12.45	
Delivery (4.6 GJ at 3.375 GJ)	15.53	
		27.98**
Commodity charges		
Midstream (4.6 GJ at 1.365 per GJ)	6.28	
Cost of gas (4.6 GJ at 2.977 per GJ)	13.69	
		19.97**
Other charges and taxes		
Carbon Tax (4.6 GJ at 1.4898 per GJ)		6.85**
HST (12% of * amounts)		6.58
Residential Energy Credit (7% of * amounts)		3.84CR
Please pay		**$57.54**

Gas usage calculation (Meter RCZ928229)

Present reading	Previous reading	Conversion factor	Gas used in gigajoules (GJ)
July 3 '12 44,682	June 1 '12 44,560 Est	0.0377178	4.6

Point of Delivery: 622258

Comparison to previous year

Billing period	Number of days billed	Average daily temp.	Average daily usage GJ	Total billing period usage GJ
July '12	32	16°C	0.14	4.6
July '11	30	15°C	0.09	2.7

Sample

Before you read the above description, were you aware of what the **Delivery** charge covers?

Yes, aware
No, not aware

Based on the description above, how well do you understand what this charge covers?

Do not understand at all				Understand extremely well
1	2	3	4	5

Based on the description above, how clear or confusing is it to have the Delivery charges separated by a **Basic charge** and a **Delivery charge**?

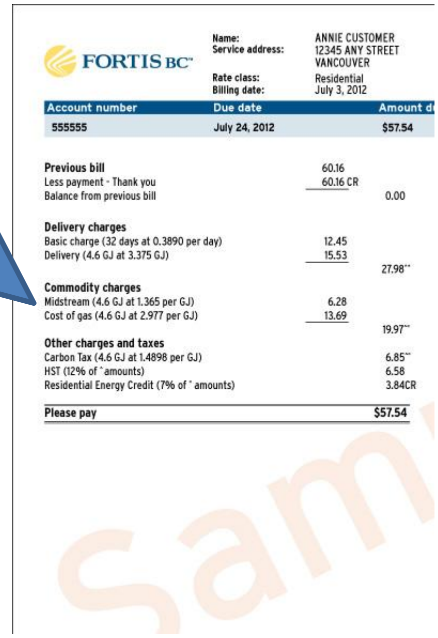
Very confusing				Very clear
1	2	3	4	5

Midstream Charge

Now please look at the Commodity charges. Here you will see a **Midstream** charge.

Midstream charge

- Cost that FortisBC pays to store and transport the gas delivered to customers
- Calculated on a per Gigajoule basis
- You are charged for the energy used during the month so we multiply your monthly consumption (4.6 GJ) by the Midstream charge per unit of energy ($1.365/GJ)



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HST (12% of * amounts)		6.58
Residential Energy Credit (7% of * amounts)		3.84CR
Please pay		**$57.54**

Before you read the above description, were you aware of what the **Midstream** charge covers?

Yes, aware
No, not aware

Based on the description above, how well do you understand what this charge covers?

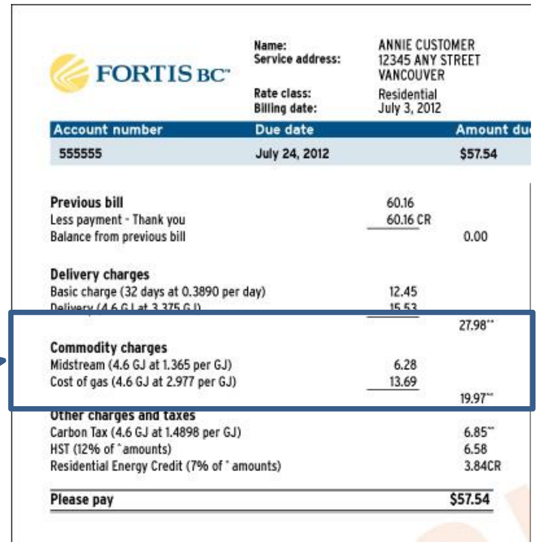
Do not understand at all				Understand extremely well
1	2	3	4	5

Cost of Gas Charge

Still looking under Commodity charges, you will see a **Cost of gas** charge.

Cost of gas charge

- The charge for the commodity (gas) that you've used
- Calculated on a per Gigajoule basis so we multiply your monthly consumption (4.6 GJ) by the Cost of gas charge for each unit of energy ($2.977/GJ)



FORTIS BC

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Rate class: Residential
Billing date: July 3, 2012

Account number	Due date	Amount due
555555	July 24, 2012	$57.54

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Less payment - Thank you 60.16 CR
Balance from previous bill 0.00

Delivery charges
Basic charge (32 days at 0.3890 per day) 12.45
Delivery (4.6 GJ at 3.375 GJ) 15.53
27.98**

Commodity charges
Midstream (4.6 GJ at 1.365 per GJ) 6.28
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Other charges and taxes
Carbon Tax (4.6 GJ at 1.4898 per GJ) 6.85**
HST (12% of * amounts) 6.58
Residential Energy Credit (7% of * amounts) 3.84CR

Please pay $57.54

Before you read the above description, were you aware of what the **Cost of gas** charge covers?

Yes, aware
No, not aware

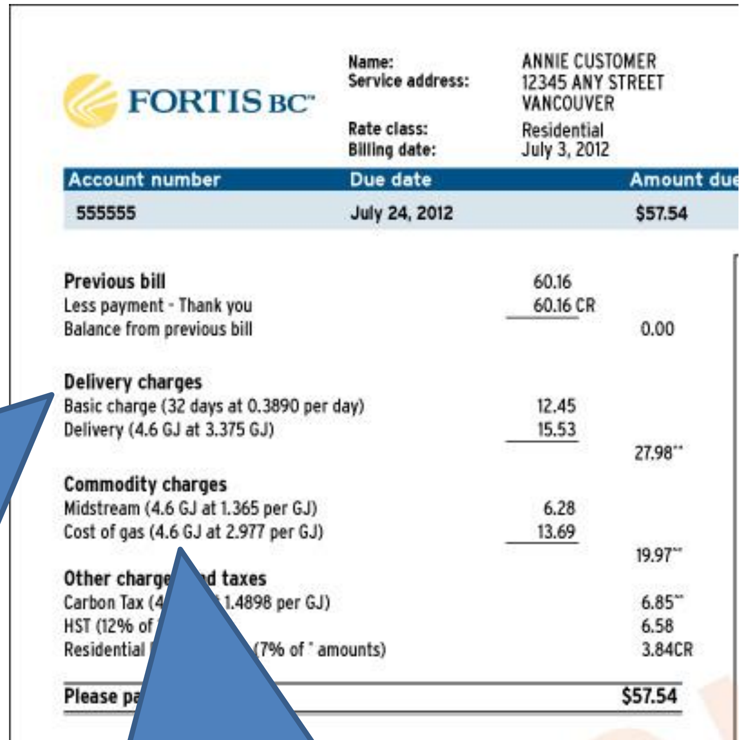
Based on the description above, how well do you understand what this charge covers?

Do not understand at all				Understand extremely well
1	2	3	4	5

How FortisBC makes its profit.

- Like a freight company charges you to take a parcel from point A to B, FortisBC charges you to deliver gas through its pipelines. And just like the freight company, part of their Delivery charge includes a profit margin. Once operating costs are looked after, the balance remaining is how they make their profit.

- This Delivery charge is reviewed and approved by the BC Utilities Commission to ensure that customers are protected and that FortisBC's profits are fair and reasonable.



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HST (12% of [...]		6.58
Residential [...](7% of * amounts)		3.84CR
Please pa[...]		**$57.54**

- FortisBC buys the gas on the open market.

- You pay the same rate that FortisBC pays on the open market.

Prior to today, were you aware that you pay the same charge for your natural gas that FortisBC pays and that FortisBC makes its profit only on the delivery of the gas?

Yes
No
Don't know

Do Not Turn this Page

Equal Payment Plan

The monthly payment for FortisBC's Equal Payment Plan (EPP) is estimated based on historical consumption at the address. Changes in gas use, new appliances, weather and rate changes can all affect the amount people actually owe. Right now, FortisBC adjusts EPP instalment payments every quarter to reflect changes in the actual cost of natural gas and the household's gas consumption. By doing so, the possibility of making a larger adjustment at the end of the year is reduced. Before today, did you know that FortisBC may adjust EPP monthly instalment amounts each quarter?

Yes
No

FortisBC could change how often it adjusts EPP monthly instalment amounts. For example, it could adjust instalment payment amounts on a semi-annual or annual basis. Another option is to adjust the instalment amount after nine months. By the end of each year, however, customers need to have paid for the gas that was actually used.

The main difference between the four options is the frequency in which the monthly installment payments can change and the potential size of the annual adjustment:

- The more frequently monthly payments are adjusted, the smaller the annual adjustment typically needs to be.
- The less frequently monthly payments change, the larger the annual adjustments may need to be.

If you were on EPP, which adjustment period would you prefer for your natural gas bill?

Quarterly (four times a year)
Semi-annually (twice a year)
Annually (once a year)
9-month adjustment (once every 9 months)

Independent Natural Gas Marketers (Customer Choice Program)

By signing a contract with a gas marketer, you commit to purchase natural gas at a fixed price for terms between one to five years. Marketers include a markup in their cost of gas rate that allows them to cover their costs and earn a profit. The total amount you pay over a contract's period could end up being more or less than what you would be charged by FortisBC for the same period. It all depends on how volatile the price of natural gas is on the open market. The choice is like a homeowner locking into a mortgage at a fixed rate instead of a variable rate where the price can change.

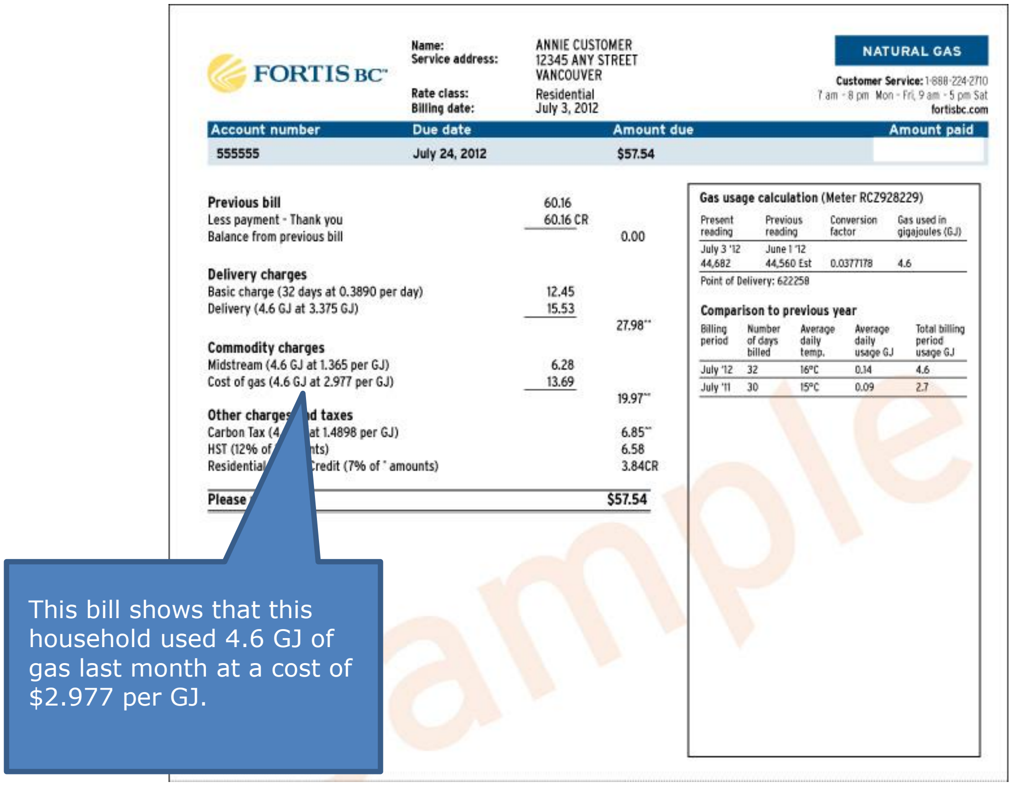
How likely would you be to sign up with an independent gas marketer in the next year?

Definitely would not	Probably would not	Might or might not	Probably would	Definitely would
1	2	3	4	5

Why do you say that?

Pay the market rate for natural gas

As noted earlier, customers pay what FortisBC pays for natural gas on the open market. To limit the unpredictability of natural gas prices, FortisBC can change how often natural gas rates are adjusted. You could choose a quarterly adjustment date (four times a year like FortisBC does now), or a semi-annual (twice a year), or annual date (once a year).



Here’s how this program would work:

- You pay what FortisBC pays for natural gas on the open market.
- You choose a rate adjustment period – quarterly, semi-annual, or annual.
- Less frequent adjustments could result in larger rate changes occurring in the future.
- More frequent adjustments could result in smaller rate changes in the future.
- There would be no additional administration fees for this service

	Very difficult				Very easy
How easy or difficult is it to understand this option?	1	2	3	4	5

Your gas bill will fluctuate based on the amount of gas you use and the market price of natural gas.

Fortis BC adjusts rates to reflect market prices. Currently, they adjust the commodity charge quarterly. What adjustment period would you most likely choose if you had a choice?

Quarterly
Semi-annual
Annual

Price Protect

The main feature of this option is that it reduces the unpredictability of natural gas rates.

With this program, FortisBC can purchase the natural gas you'll need tomorrow by locking in supply at today's rates. Here's how this program would work:

- You choose how long you want to participate in the program from six months up to three years.
- You choose to lock in the rate for **all** or **half** of your gas usage.
- If you lock in the rate you pay for all gas used, the option is like a fixed rate mortgage. They are "peace of mind" products designed to protect you from rising natural gas prices and may or may not save you money. If the locked in price is lower than market price, you pay less than you otherwise would. But, if the market price for natural gas drops below the locked in price, you pay more than you otherwise would. In essence, by choosing the price protect option you believe the price of natural gas is going to rise above your contracted rate.
- An administration fee will be incurred to participate in this program.

	Very difficult				Very easy
How easy or difficult is it to understand this program?	1	2	3	4	5

	Definitely would not	Probably would not	Might or might not	Probably would	Definitely would
How likely would you be to sign up for this option if it were offered?	1	2	3	4	5

Rate Cap

Another way of reducing the unpredictability of natural gas rates on the open market is by offering customers a capped rate. Here's how this program would work:

- You pay a monthly premium in addition to the actual cost of the natural gas to secure the capped rate.
- You choose how long you want to participate in the program from six months up to three years.
- If the cost of natural gas rises above the capped rate, you only pay up to the capped rate, so you pay less than you otherwise would.
- If the cost of natural gas drops, you still pay the monthly premium but benefit by paying the new lower rate.
- In essence, this option is similar to an insurance policy that protects you from rising natural gas prices. Yet it does not lock you in to a set rate, so you still benefit if prices drop.
- An administration fee will be incurred to participate in this program.

	Very difficult				Very easy
How easy or difficult is it to understand this option?	1	2	3	4	5

	Definitely would not	Probably would not	Might or might not	Probably would	Definitely would
How likely would you be to sign up for it if it was offered?	1	2	3	4	5

Rate Protect

Choose your preferred level of Rate Protection

Rate Protect offers another way to reduce the unpredictability of natural gas rates.

A FortisBC "Stability Fund" will be built up by customers who choose this program. Here's how this option would work:

- Customers pay a premium in addition to the current natural gas rate. Over time, this premium accumulates in a FortisBC Stability Fund. It's like a rainy day fund.
- When the cost of natural gas is lower than the rate that participating customers are paying, the difference is deposited into the Stability Fund.
- When the cost of natural gas is higher than the rate participating customers are paying, some or all of the difference could be offset by using what's in the Stability Fund. This would minimize the impact of higher gas rates.
- An administration fee will be incurred to participate in this program.

	Very difficult				Very easy
How easy or difficult is it to understand this option?	1	2	3	4	5

	Definitely would not	Probably would not	Might or might not	Probably would	Definitely would
How likely would you be to sign up for it if it were offered?	1	2	3	4	5

Program Summary

Which one do you prefer and Why?

Pay the market rate for natural gas. You pay what FortisBC pays for natural gas on the open market. This cost is adjusted on the rate adjustment date you prefer, which could be quarterly, semi-annually, 9-month or annually.

Price Protect. FortisBC buys the natural gas that you'll need tomorrow by locking in supply at today's rates. You can choose to have half or all of your gas usage locked in and you can choose how long you wish to participate in this program.

Rate Cap. Customers pay a premium to ensure the natural gas rates they pay do not exceed the capped rate for the term of the contract.

Rate Protect. Customers paying a premium over current natural gas rates will build up a FortisBC Stability Fund over time. The funds will be used to offset potential higher rates at a later date.

<u>FortisBC Rate Alternative Guide</u>

Pay the market rate for natural gas

Customers pay what FortisBC pays for natural gas on the open market. FortisBC would use the rate adjustment date a customer prefers which could be quarterly, semi-annually, 9-month or annually.

Price Protect

FortisBC buys the natural gas that customers will need tomorrow by locking in supply at today's rates. Customers could choose to have half or all of their gas usage locked in and they could choose how long they wish to participate in this program.

Rate Cap

Customers pay a premium to ensure the natural gas rates they pay do not exceed the capped rate for the term of the contract.

Rate Protect

Customers pay a premium over their current natural gas rate that, over time, builds into a Stability Fund. The funds will be used to offset potential higher rates later.

Appendix E

2012 CUSTOMER RESEARCH RESULTS PRESENTATION

Alternatives for Managing Natural Gas Price Volatility

October 22, 2012

Prepared By:

Lorraine Macdonald, Principal, Sentis

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Gerry Keane, Principal, Participant Research

Tel: 604-339-8620, Email: gerry.keane@participantresearch.ca

Presentation Topics

- Research Objectives
- Methodology
- Key Findings by Research Objective
- Summary of Recommendations

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Broad Objective

To understand customer perceptions of pricing volatility and potential volatility management programs.

Specific Objectives

- Understanding of:
  - current bill
  - natural gas pricing
  - concern about natural gas prices and their tolerance for volatility and/or general commodity cost increases
- Awareness and use of Equal Payment Plans and preference for frequency of rate adjustments
- Test understanding and preference for various alternative rate options
- Identify communication barriers to their introduction

Methodology - Quantitative

- Method: Online Survey
- Target Groups: Resident and Business Customers
- Sample Size: 800 Residents and 204 Businesses
- Weighted data for analysis
- Margins of Error

Methodology – Qualitative

- Eight focus groups:
  - Four residential
  - Four business
- Vancouver and Kelowna
- September 24 to 27, 2012

Qualitative Research Limitations

- Results are not projectable to any population
- Participants are not selected randomly
- Qualitative research does not carry any quantitative characteristics
- All ideas are explored and as many opinions as possible are elicited

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KEY FINDINGS

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Key Learnings

- Low understanding of the FortisBC bill structure
- Low awareness that FortisBC only profits on the delivery charge
- Consider rate options but limit choices
- Evaluate bill for possible improvements,(i.e. eliminate jargon and simplify)

Understanding of Current Bill

Differences between Delivery charges & Commodity charges

	% understand
Residential	35%
LICO	30%
Business	45%

	% clear
Residential	36%
LICO	29%
Business	45%

FORTIS BC

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Sample

What is Midstream Charge?

	Rating 4-5 out of 5		
	Residential	LICO	Business
Basic Charge	57%	40%	63%
Delivery Charge	56%	39%	67%
Midstream Charge	42%	31%	50%
Cost of Gas	58%	41%	63%
Clarity of Basic vs. Delivery	50%	36%	62%
Clarity of Midstream vs Cost of Gas	42%	32%	51%

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Understanding of the FortisBC Bill

- Fair to poor understanding;
- Recall few charges:
  - Total
  - Taxes
  - Delivery charge
  - Basic charge
- Surprised of no profit on gas sales;
- Midstream and Delivery Charge confusion;
- FortisBC meant to foster understanding but had made it worse.

"Somebody somewhere, some place thought we'd understand this. But we don't."

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Does FortisBC Mark Up Cost of Natural Gas?

Those aware that FortisBC makes a profit only on the delivery of gas:

- Residential - 27%
- LICO - 32%
- Business – 23%

FortisBC customers – 28%

Gas Marketer – 20%

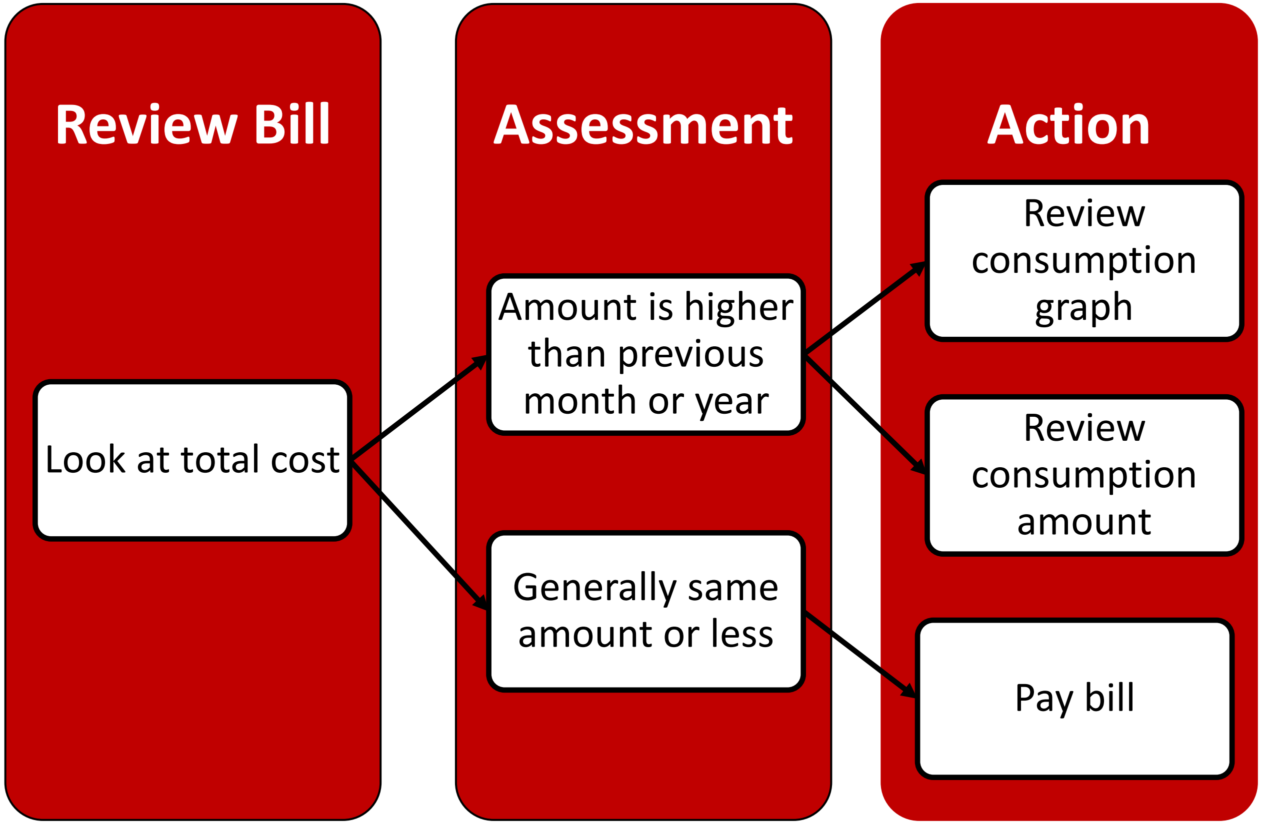
Recommendation:

Re-evaluate communications strategy/approach.

Message isn't getting through.

Reading Their Bills

- People tend to read their FortisBC bill from the bottom line upwards:



Concern About Increasing Natural Gas Prices

	Rating 4-5 out of 5		
	Residents	LICO	Business
Gasoline	80%	74%	83%
Electricity	68%	67%	75%
Natural Gas	64%	62%	69%
Interest Rates	57%	52%	53%
Housing/ Commercial Property	44%	60%	49%
Internet	50%	58%	46%

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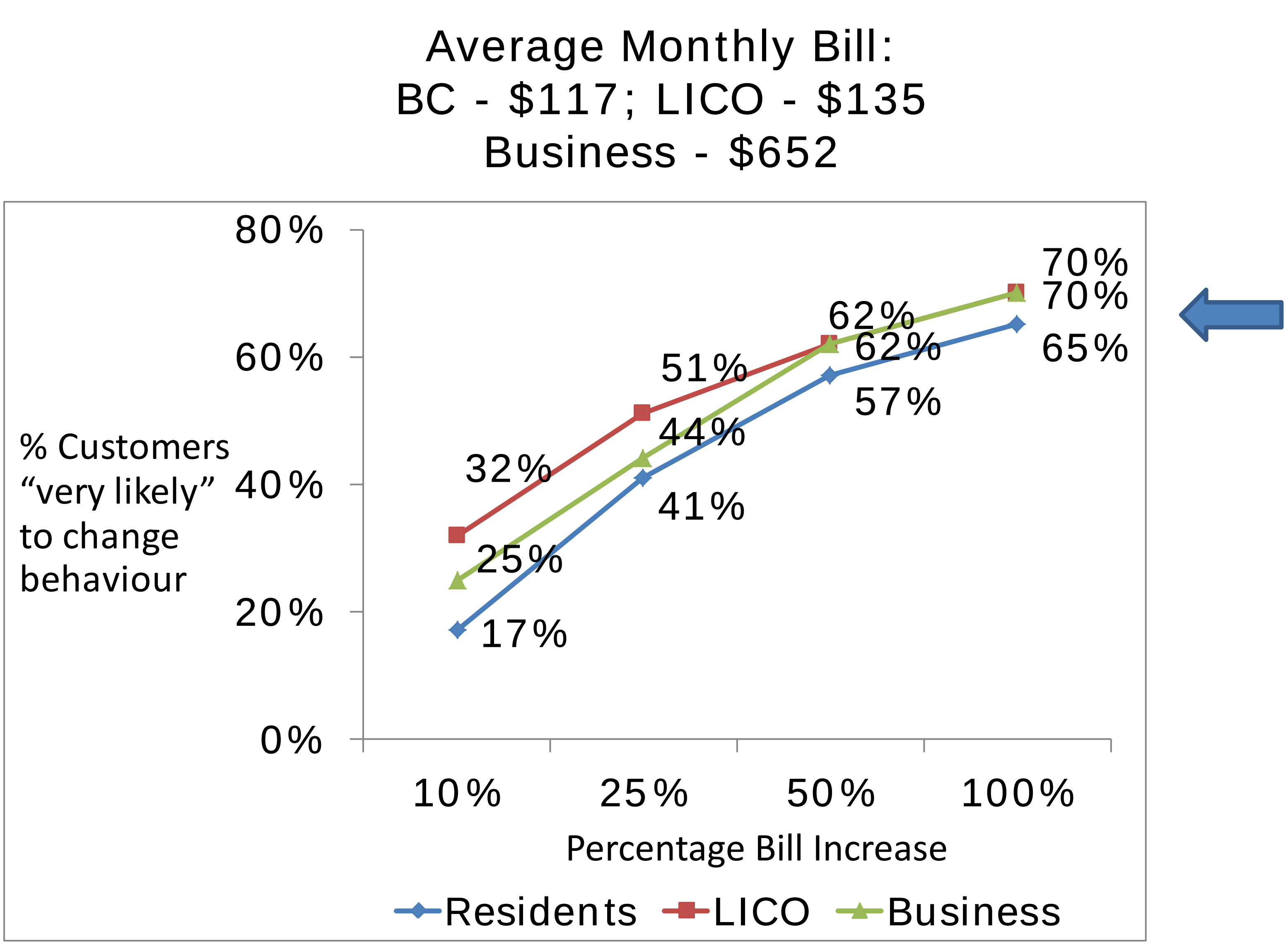
Natural Gas Price Influences Behaviour



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Customer Choice Program

	Residential	LICO	Business
Currently Purchasing from Gas Marketer	13%	6%	13%
Contract Expired, back with FBC	5%	7%	17%
Never with GM	62%	56%	56%

Why Gas Marketer? Protection against increasing gas rates.

Why NOT Gas Marketer? Prefer FortisBC, don't trust gas marketer.

Gas Marketer or FortisBC for Similar Options

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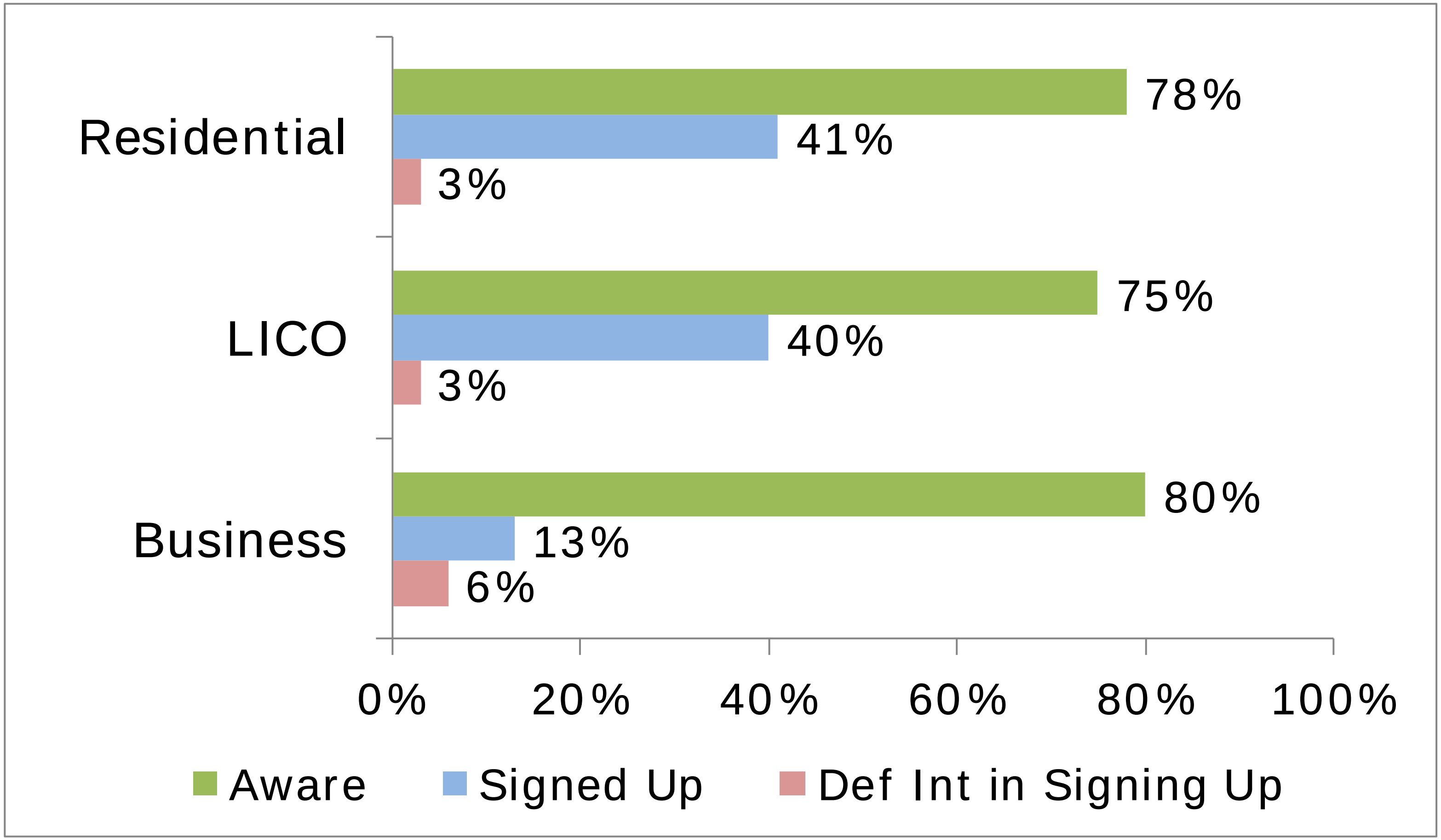
Customer Choice Program

- Respondents had only negative comments about gas marketers:
  - "Locked in at high prices."
  - "Unsound marketing practices."
  - "Aggressive sales techniques."
  - "Contracts that have too much 'fine print.'"

Awareness and Use of FBC Gas EPP



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Equal Payment Plan

- High program awareness
- Makes budgeting easier
- Those not on EPP assumed that no consumption data would be on their bill
- Small business like the program
- Interest in rolling average but difficult to understand
- Name may not fit the program

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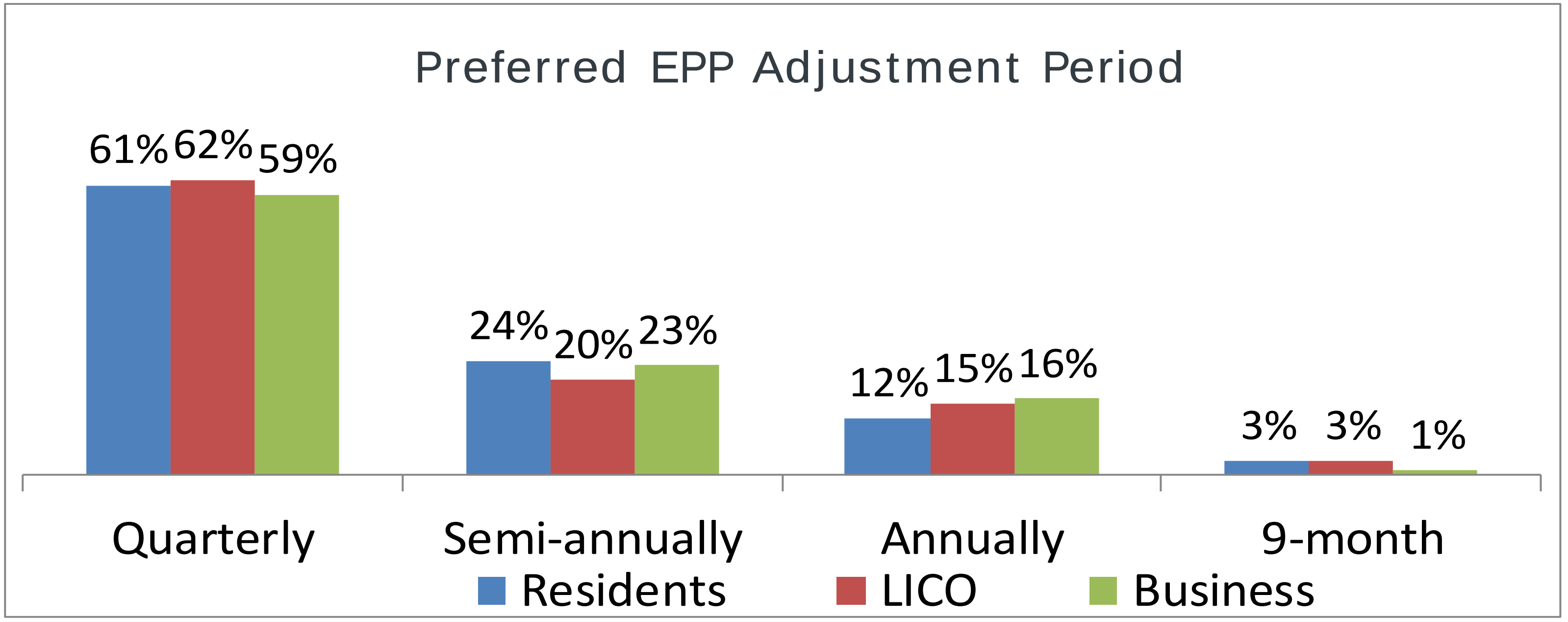
EPP Adjustment Period & Preferences

Aware that FortisBC may adjust EPP each quarter:

Residential - 44%

LICO – 47%

Business – 25%



Recommendation: Keep EPP on quarterly adjustment period.

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Alternative Rate Options Explored

- Pay the market rate for natural gas
- Price Protect
  - FortisBC buys natural gas at today's rates for use tomorrow
- Rate Cap
  - Premium product ensures rates do not exceed capped rate
- Rate Protect
  - Pay into stability fund

SENTIS measuring what matters

Ease of Understanding Options

	Rating 4-5 out of 5		
	Residential	LICO	Business
A. Pay the market rate for natural gas	55%	37%	63%
B. Price Protect	49%	37%	59%
C. Rate Cap	48%	38%	60%
D. Rate Protect	48%	33%	55%

Preferred Option

	Residential	LICO	Business
A. Pay the market rate for natural gas	41%	32%	41%
B. Price Protect	17%	13%	18%
C. Rate Cap	10%	14%	10%
D. Rate Protect	11%	13%	6%
E. Don’t know	19%	27%	23%

Recommendation: Don’t give consumers too many options.

Price Protect

Focus group respondents said:

- Too much like a gas marketer
- Makes more sense in very volatile times
- Price does not go down when the commodity price decreases

"So, Fortis wants to be in the insurance business now?"

"I would prefer to pay the market rate… but if it seems that the cost is going to rise I may go for the Rate Protect."

Rate Cap

- Of all the potential programs, this one was the most favoured because it offered a cheaper rate if the commodity price comes down

- Essentially, they wanted to avoid being locked in at a high price when everyone else is paying much less

"I like that I can take advantage of a lower rate."

"There is built-in flexibility."

Rate Protect

- This was poorly regarded by most
- Concern about FortisBC becoming a banker:
  - Who would watch it?
  - How is it used?
  - Seemed too complicated
  - Refunds

"What happens if I move away from here. Will I get my money back?"

"Who is going to police the fund?"

Communication Barriers

"This bill has just too much information."

Low bill understanding

+

Low u/s of how FortisBC makes a profit

=

Low understanding of rate options

"I would pay the market rate because it is clear to me."

"I had no idea they didn't make money off the cost of gas."

SENTIS measuring what matters

Recommendation Summary

- Customers want fewer – not more - options
- Best programs were:
  - Pay market rate(quarterly adj.)
  - Equal Payment Plan (quarterly adj.)
  - Rate cap
  - Rate protect (lowest)

- Improve bill
  - eliminate jargon and simplify
- Review rate communications strategy
  - Reinforce key messages
  - Consider other channels and message timing

Thank You

Questions?

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Appendix F

2005 CUSTOMER RESEARCH RESULTS

TERASEN GAS

RESIDENTIAL CUSTOMER
NATURAL GAS PRICE VOLATILITY PREFERENCES
QUALITATIVE RESEARCH STUDY
FEBRUARY 2005

Detailed Report

March 14, 2005

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Executive Overview

Introduction

In February 2005, Terasen Gas engaged Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[1] residents (one group on the EPP[2], one Group not on the EPP)
- 2 Groups with CRD residents[3] (one group on the EPP, one Group not on the EPP)

Phase 2 of the project, will consist of a telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

This report summarizes the results of Phase 1 of the research, which will be used to identify the range of opinions on the subject and aid in the development of a questionnaire in Phase 2. The objective of Phase 2 will be to quantify the findings from the qualitative phase, and to examine important differences in sub-groups.

[1] Greater Vancouver Regional District
[2] Equal Payment Plan
[3] Capital Regional District (Vancouver Island)

Key Findings

1. Concerns about the price or price volatility of natural gas were not top-of-mind among most participants.

    - In the questionnaire administered to participants just prior to the discussion, natural gas prices were considered to have increased slightly over the past year, which was about the same as for electricity, and fruits and vegetables. Results show that of the five product and service categories, gasoline prices were considered to have increased the most over the past year; to have had the greatest price volatility; and to be the greatest concern to participants (68%). In contrast, natural gas price increases were cited as being the main concern by only 13 percent of participants, which was the same as for electricity (13%).
    - During the opening discussion about their natural gas bill and their household natural gas service, relatively few commented or complained about natural gas pricing or price volatility.
    - While there was some awareness of a longer term increase in the price of natural gas, few commented about price fluctuations in natural gas.
    - Vancouver Island participants were more attuned to the price of natural gas as compared to electricity. This is not unexpected as many said they had recently converted some of their appliances or heating over to gas from electricity with the expectation of saving money.
    - Largely, participants said they did not automatically assume that changes in their bill were due to price fluctuations.

2. The natural gas bill is a significant monthly expense and while it is not closely reviewed every month, participants do periodically review it to examine their consumption and assess their energy conservation efforts.

    - The natural gas bill was typically not viewed as being the largest bill for participants, but was considered among the more "significant" monthly payments, particularly among those with fixed incomes or no mortgage payments.
    - Periodically people said they reviewed their consumption, often utilizing the graph provided on the bill to compare usage over the past year and the average temperature. In this regard a number of participants said they reviewed their bills to determine if their energy conservation efforts were effective or not.

3. Awareness of the components of monthly billing charges was relatively low.

4. There was some awareness of what caused fluctuations in natural gas prices, but there were misconceptions as well.

    - When asked what caused fluctuations in natural gas prices, participants correctly identified supply and demand, weather / seasonal factors, and the costs of exploration, among other factors.
    - A number of misconceptions emerged as well, with a few participants citing profits or inflated executive salaries by Terasen Gas, or the belief that British Columbians should pay less for natural gas because natural gas is extracted in BC.

5. Awareness of activities or programs by Terasen Gas to control natural gas price fluctuations was very low, though some "assumed" this was the case.

   - There was a low awareness of measures by Terasen Gas to control fluctuations in the price of natural gas. Few participants actually knew that Terasen Gas did this but several assumed or guessed that Terasen followed this practice with the view that "a responsible company has to manage the price of gas".

6. Most participants were supportive of Terasen Gas' current approach to hedging, and preferred this approach over the "more" or "less" hedging alternatives.

   - Feedback from participants was that they were largely supportive of the current Terasen Gas hedging practice, though a few wondered if this practice was regulated.
   - When given the choice among three hedging scenarios, most (29 of 34) participants said they preferred the current approach because they didn't like or could not afford big price increases on their gas bill; that it was helpful for budgeting; that the current practice could benefit from price decreases; and that they thought it might provide lower average pricing than the 100% fixed scenario.
   - Four participants preferred the "100% hedging" approach mainly because it eliminated fluctuations in their gas bill which was helpful in budgeting.
   - One participant preferred the "Almost No Hedging Strategy" because this approach would allow them to "know what they bought" and they would not have to "rely on" or need to "trust" the hedging strategy. When probed further by the moderator this individual's pricing volatility tolerance was actually closer to the current hedging program.

7. On average, participants said they could "live with" a $169 change in their annual natural gas billings which represents 16% of participants' annual natural gas billings. As might be expected, the maximum change in annual gas billings that participants say they can live with tends to vary based on their total annual natural gas billings.

   - The average (estimated) annual natural gas billings for group participants was $1033, and the maximum amount of change in their annual natural gas billings they were willing to live with was $169.
   - As might be expected, the maximum change in annual gas billings that participants say they can live with tends to increase as their annual gas billings increase. Results show that for total annual natural gas billings of less than $900, the average amount of change participants could live with in their annual gas billings was $53 (or 11% of total annual billings under $900). For total annual natural gas billings of $900 or more, the average amount of change per year participants could live with was $219 (or 17% of total annual billings of $900 and over).
   - As expected, the average estimated annual natural gas billings for the Vancouver Island participants was lower than for the GVRD participants ($689 vs. $1287). Accordingly, the average amount of annual change in natural gas billings Vancouver Island participants were willing to accept was also lower ($90 versus $227).
   - Those preferring the 100% Hedging Scenario were less tolerant to price fluctuations. As a percentage of their total annual gas bill, those choosing the 100% Hedging Scenario would only accept a maximum change of 4% over the year,

which is lower than those choosing the Current Program who would tolerate (on average) a maximum change of 19%.

8. The Equal Payment Plan was perceived as having both benefits and drawbacks. Those who favoured the EPP mentioned that it kept monthly household natural gas costs stable (i.e., no surprises on the monthly bill), which is helpful for budgeting purposes.

   Drawbacks of the EPP were that no interest is given on the pre-paid money (although another commented that Terasen Gas does not charge interest for EPP funds owing either).

   - Reasons for not going on the EPP were that participants wanted to see and monitor their actual gas consumption; they liked having lower payments in summer to better match to their income flow; or they wanted to monitor their efforts to conserve energy.

Foreword

Background and Research Objectives

In February 2005, Terasen Gas engaged Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

The objectives of the research were to:

- Define customers' level of understanding regarding natural gas rates – including their components and how rates are set.
- Understand customer risk preferences regarding rates and determine if price points exist where customers are willing to accept more risk in the form of rate variability and where they desire less risk through rate stability.
- Use the results to revise Terasen Gas's price-risk management hedging strategy as appropriate.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[4] residents (one group on the EPP[5], one Group not on the EPP)
- 2 Groups with CRD residents[6] (one group on the EPP, one Group not on the EPP)

Phase 2 of the project, will consist of a telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

This report summarizes the results of Phase 1 of the research, which will be used to identify the range of opinions on the subject and aid in the development of a questionnaire in Phase 2.

Phase 2 of the research will quantify the findings from the qualitative phase, and examine importance differences in sub-groups.

[4] Greater Vancouver Regional District
[5] Equal Payment Plan
[6] Capital Regional District (Vancouver Island)

Methodology

Phase 1: Focus Groups with Residential Gas Customers

Four focus groups were held with residential gas customers of Terasen Gas on February 7th (GVRD) and 8th (CRD) 2005, as follows:

- 2 Groups with GVRD residents (one group on the EPP, one Group not on the EPP)
- 2 Groups with CRD residents (one group on the EPP, one Group not on the EPP)

Both groups were held in focus group facilities equipped with one-way mirrors for observers, boardroom-style meeting room and audio-visual recording equipment.

Participants were recruited from customer lists provided by Terasen Gas. Individuals in the household who were most familiar with buying and paying for the household's natural gas were targeted. To encourage participation, a $60 cash incentive was provided. Ten customers were recruited for each group for eight to participate (though up to ten were allowed to participate if they arrived. To be eligible to participate in the groups participants must have met the following criteria:

- Individuals and the members of their household could not be employed by Terasen Gas or subsidiary of Terasen Incorporated, a natural gas distributor, producer or natural gas marketer, the media, advertising, or a market research firm;
- They must live within the boundaries of the GVRD/CRD;
- They could not have attended a focus group within the past 12 months; and
- They could not have attended more than five focus groups in the past five years.

To ensure a broad representation of Terasen Gas residential customers, efforts were made to recruit a mix of:

- Males and females;
- Owners and Renters (though the sample was heavily weighted to Owners);
- Those residing in single family as well as multi-family dwellings;
- Residents from a range of communities within the GVRD/CRD; and
- Customers representing a range of age, education, household income and occupational categories.

<u>A Note Regarding the Context of Qualitative Research</u>

The primary benefit of focus group discussions is that they allow for in-depth probing with qualifying participants on behavior, habits, usage patterns, perceptions and attitudes that relate to the subject matter. The group discussion allows for flexibility in exploring other areas that may be pertinent to the investigation.

The focus group technique is used in marketing research as a means of gaining insight and direction, rather than collecting quantitatively precise data or absolute measures. Although numbers are sometimes presented as illustrative of the opinions of the participants in this study, these are offered for insight and should not be considered statistically reliable.

Detailed Findings

1.0 Pre-Exercise: General Concern about Natural Gas Price Volatility

As part of the focus groups, participants were asked to complete two questionnaires. The first questionnaire was completed by participants just prior to the start of the groups. The purpose of this first exercise was to gauge participants' level of concern about price volatility in each of five product/service categories. It also prepared participants for the upcoming discussion about natural gas price volatility.

Results show that of all the product and service categories, gasoline prices were considered to have increased the most over the past year, to have had the greatest price volatility; and to be the greatest concern to participants (68%). In contrast, natural gas price increases were cited as being the main concern by only 13 percent of participants, which was the same as electricity (13%).

Results were virtually the same with respect to perceptions about the coming year.

The following bullet-points summarize the findings.

Perceptions of price volatility in the past year

With respect to the price volatility of the five product service categories over the past year, most participants thought:

- That the price of gasoline had increased *significantly*
- The price of electricity had increased *slightly*
- That the price of natural gas had increased *slightly*
- That the price of fruits and vegetables had increased *slightly*
- That phone charges had *stayed the same* or increased *slightly*

- Increases in the "price of gasoline" was most frequently cited as concerning participants the most (by two-thirds). Only 13% cited increases in the price of natural gas as being a concern, while another 12% cited being concerned about increases in the price of electricity.
- Gasoline was most frequently cited as having the greatest price volatility (88%). Natural gas was cited by 3% as having had the highest price volatility.
- Phone services (45%) and fruits and veggies (32%) were more frequently cited as having the lowest price volatility. Natural gas was cited by 6% as having the lowest price volatility.

Perceptions of price volatility in the coming year

With respect to the price volatility of the five product service categories over the next year, most participants thought:

- That the price of gasoline will increase *significantly or slightly*
- The price of electricity will increase *slightly*

- That the price of natural gas will increase *slightly*
- That the price of fruits and vegetables will increase *slightly*
- That phone charges will *stay the same* or increase *slightly*

- Increases in the "price of gasoline" over the next year was most frequently cited as concerning participants the most (by two-thirds). Only 13% cited increases in the price of natural gas as being a concern, while another 13% cited being concerned about increases in the price of electricity.
- Gasoline was most frequently cited as having the greatest potential price volatility (88%). Only 6 percent think natural gas will have the greatest price volatility.
- Phone services (56%) was most frequently cited as having the lowest price volatility.

2.0 General Natural Gas Customer Observations

Following the opening statements by the moderator and the round-table introductions, participants were asked to give their general views about their natural gas bill (examples of which were circulated), as well as their top-of-mind impressions about their household natural gas service. Relatively few commented or complained about natural gas pricing or price volatility. The following bullet-points summarize participants' comments.

- Frequently people pay their natural gas bill without closely reviewing their usage or price fluctuations other than checking the amount to be paid and the due date. Periodically people do review their consumption, often utilizing the graph provided on the bill to compare usage over the past year and the average temperature. Several participants commented that they would like the graph to cover a longer time period than currently provided. In this regard, a number of participants said they reviewed their bills to determine if their energy conservation efforts were effective or not.
- A few commented that sometimes they had difficulty reconciling their gas bill charges with their usage, or wondered why the charges were so high during the summer. One participant said it would be helpful to see information about how their gas consumption compared to other similar size houses.
- A few complained about not being able to pay their bill with their credit card or having to pay a service charge to do so.
- Awareness of the various components of the natural gas bill charges was relatively low.
- There were some misconceptions that Terasen Gas made a profit by marking up the natural gas commodity.
- Positive comments were that Terasen Gas has provided good, responsive service, and that people liked the graph on the bills showing past consumption.
- Less positive comments were that Terasen Gas was a "monopoly" or that some services offered by BC Gas were no longer offered by Terasen Gas.
- Some participants were confused about the name change and what its purpose was except that it was costly and served no benefit to the customer.
- Relatively few commented or complained about natural gas pricing or price volatility. When prompted about pricing, participants were mixed with some saying the cost of natural gas was reasonable, while a few said that it was too expensive. When asked if gas prices changed, the general response was that they changed only a little bit.

3.0 Price Fluctuations

Next, the discussion moved to natural gas price fluctuations. There was awareness of longer-term increases in natural gas, but less awareness of quarterly natural gas pricing adjustments. In this respect, there was some confusion between the timing of price adjustments and periodic adjustments to the monthly EPP amount. Typically, however, changes in monthly billing amounts were attributed to changes in consumption rather than the price of natural gas.

When asked what caused fluctuations in natural gas prices, participants correctly identified supply and demand, weather / seasonal factors, and the costs of exploration, among other factors. A number of misconceptions emerged as well, with a few participants citing profits or inflated executive salaries by Terasen Gas, or the belief that British Columbians should pay less for natural gas because natural gas is extracted in BC.

Awareness of activities or programs by Terasen Gas to control natural gas price fluctuations was very low; only those with related occupational knowledge were aware of this. A few other participants assumed that Terasen did this, but didn't know for sure.

The following bullet-points summarize the findings.

Awareness of Price Fluctuations and their Cause

- A number of participants said that over the longer-term, there had been a trend of increasing natural gas prices.
- In one group, there was a misconception that Terasen Gas had recently applied for a rate increase, when in fact this was BC Hydro.
- On Vancouver Island, participants were more attuned to the price of natural gas as compared to electricity.
- Few participants were aware of quarterly Equal Billing Payment Plan (EPP) bill adjustments for rate changes or changes in consumption.
- A few were aware that Terasen Gas periodically assessed natural gas pricing to customers and commented that this ranged from once a year to every few months to quarterly. However, there was some confusion between the periodic EPP adjustments and periodic natural gas rate adjustments by Terasen Gas.
- Participants said they found out about changes to natural gas rates on their bill from the business section of newspapers or from Terasen Gas.
- Largely, participants said they did not automatically assume that changes in their bill were due to price fluctuations.
- Fluctuations in natural gas prices were attributed to supply and demand; cost of exploration; weather and seasonal factors; profit of suppliers/shareholders; executive salaries; and the cost of electricity.
- There were a number of misconceptions about what influenced natural gas prices. A few participants commented that British Columbians should pay less for natural gas given that it is produced in BC. Others mentioned that Terasen Gas paid its executives too much. In this respect, some didn't know that the cost of the natural gas on their bills could fluctuate based on the price of natural gas on the open market.

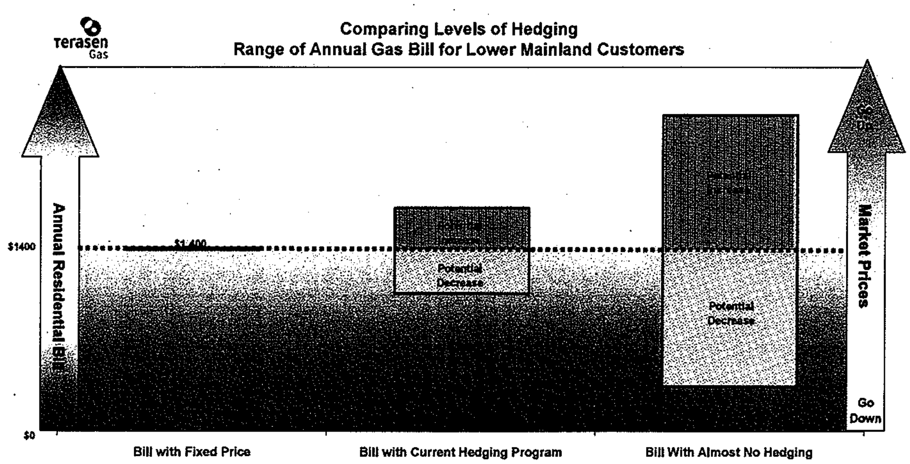
Awareness of Measures to Control Price Fluctuations

- There was a low awareness of measures by Terasen Gas to control fluctuations in the price of natural gas. Few participants actually *knew* that Terasen Gas did this but several *assumed* or guessed that Terasen followed this practice with the view that "a responsible company has to manage the price of gas".
- Only two or three participants were aware specifically of "hedging" practices by Terasen Gas to control price fluctuations, and these were people with backgrounds in banking/finance or who (had) worked in an industry with natural gas involvement (e.g. green house grower).

4.0 Hedging Preferences

Next, the moderator described the current Terasen Gas hedging program to participants in simple terms. To help convey the hedging concept, the example of fixed and variable mortgage rate plans was used. Feedback from participants was that they were largely supportive of the current hedging practice though a few wondered if this practice was regulated.

After this, two alternative hedging practices were presented (an "almost no hedging" scenario and a "100% hedging" scenario) along with the current approach. To help explain the three approaches, a graphical portrayal of the scenarios was circulated to participants. The following figure shows the example used for the two Lower Mainland focus groups. A similar chart was used for the Vancouver Island groups with the yearly average (dotted line) being $1000. Prior to discussing their preferences in the group, participants recorded their preferred hedging approach on answer sheets.



All but 5 of the 34 participants said they preferred the current approach because they didn't like or could not afford surprises (big price increases) on their gas bill; that it was helpful for budgeting; that the current practice could benefit from price decreases; and that they thought it might provide lower average pricing than the 100% fixed scenario. Virtually no participants preferred the "almost no hedging" approach, while four participants preferred the "100%

hedging" approach mainly because it eliminated fluctuations in their gas bill which was helpful for budgeting.

In a follow-up exercise, when asked the maximum dollar amount of change per year they could "live with" or "tolerate" in their natural gas billings, the most frequently cited amount was $100, while the average amount was $169. Seventy percent of participants expressed amounts of $100 or less.

The following bullet-points summarize the discussion.

Preferred Hedging Program

- Participants were largely supportive of efforts to control price fluctuations through hedging practices though a few were suspicious / wary of this practice either because they didn't fully understand it or weren't sure if this practice was regulated.
- The large majority of participants (29 of 34) preferred the existing hedging strategy employed by Terasen Gas and typically leaned more towards more hedging (100% hedging scenario) than less hedging (almost no hedging scenario).
- Reasons for preferring the existing hedging strategy were that they didn't like or could not afford surprises (big price increases) on their gas bill; it was helpful for budgeting; the current practice could benefit from price decreases, and it might provide lower average pricing than the 100% fixed scenario.
- Four participants preferred the 100 percent hedging scenario because it was helpful for budgeting, they preferred fixed pricing, or because it was viewed as less risky than the scenarios with less hedging. A couple of the participants mentioned that they could not foresee prices coming down in the next few years since natural gas is a non-renewable resource, and therefore, they would rather fix the price.
- One participant chose the "Almost No Hedging" scenario. Interestingly, this choice was not so much a preference for the pricing variability, but that it would allow them to "know what they bought" and they would not have to "rely on" or need to "trust" the hedging strategy. This person had a relatively small annual natural gas billing. When probed further by the moderator, this individual's pricing volatility tolerance was actually closer to the current hedging program.
- When asked what maximum dollar amount of change in their gas billings they could live with in a year, the most frequently mentioned amount was $100, while the average amount was $169. Seventy percent of participants expressed amounts of $100 or less. (see analysis of hedging preference questionnaire below for more details).
- The natural gas bill was typically not viewed as being the largest bill for participants, but was considered among the more "significant" monthly payments, particularly among those with fixed incomes or no mortgage payments.

Analysis of Hedging Preference Questionnaire

As mentioned earlier, participants completed a questionnaire during the group which asked them to choose which hedging strategy they preferred and why. It also asked participants to record their annual household gas bill charges along with the maximum potential change in their annual gas bill they could live with or tolerate. These results are summarized in detail here.

Participants Preferred Hedging Scenario

- Virtually all (29), but five of the 34 participants chose the "Current Hedging" program used by Terasen Gas.
- Four participants chose the "100% Hedging" scenario.
- One participant chose the "Almost No Hedging" scenario.

Reasons for Preferring the Current Terasen Gas Hedging Scenario

Avoids Large Price Increases

- The current hedging strategy helps with budgeting
- Some people cannot afford large increases
- Natural gas is viewed as a "necessity" and so should not cause financial hardship
- Fewer surprises in gas bill

Current Program a "Middle Ground" Between the Scenarios

- The current program is working well
- The current program limits price variability but leaves room to take advantage of price decreases
- The "almost no hedging" scenario is too much of a gamble
- The "100% hedging" strategy might increase the average price of natural gas.
- The perception that the "100% hedging" strategy would have fewer, but potentially larger price adjustments. The concern here was that with 100% hedging, the price would remain fixed for a given period, but at the end of this period if natural gas prices had changed drastically, their bill would also increase dramatically (as opposed to potentially more frequent but less severe price adjustments with the Current Hedging program).

Other

- The perception that the current strategy helps people to distinguish their attempts to conserve energy. We hypothesize that this comment stems from the view that holding the price of gas more constant allows people to more easily track changes in consumption.

Reasons for Preferring the 100% Hedging Scenario

- Stable natural gas pricing
- Helps with budgeting
- Less risky than other scenarios
- Fixed pricing acts almost like the Equal Payment Plan ("Prices go up in winter and down in summer, so I might as well have fixed prices")
- Natural gas is a non-renewable resource; therefore, prices are anticipated to keep rising in the near future

Reasons for Preferring the Almost No Hedging Scenario

- This participant said this approach would allow her to "know what she bought" and would not have to "rely on" or need to "trust" the hedging strategy. When probed further by the moderator, this individual's pricing volatility tolerance was actually closer to the current hedging program.

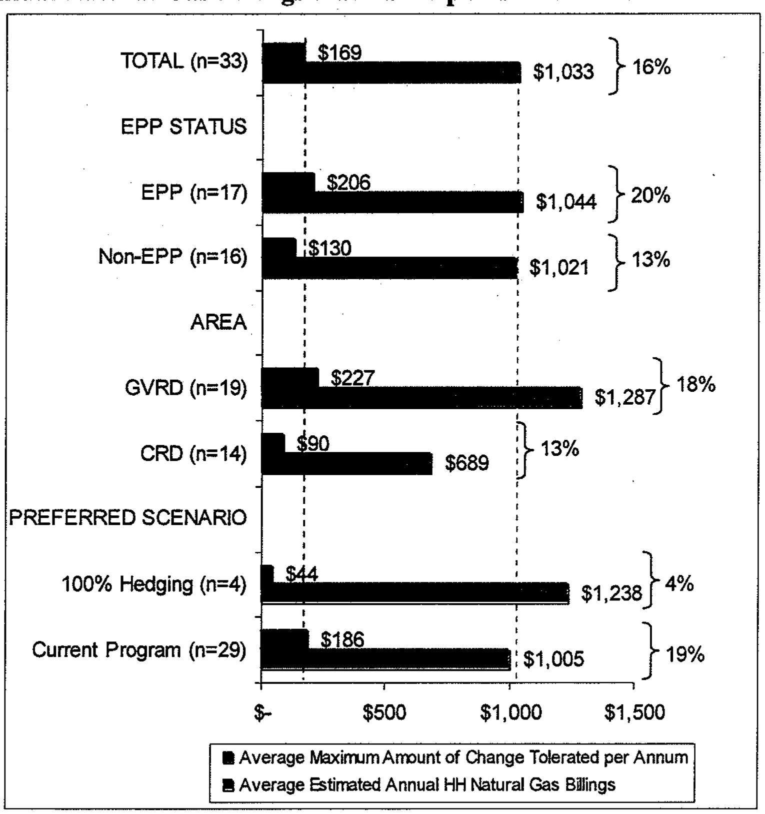
Tolerance for Natural Gas Price Volatility

Next, participants estimated their household's total annual natural gas billings, and with this in mind, recorded the maximum amount of change in their annual gas billings that they could live with or tolerate. The following chart summarizes the *average* results along with the maximum acceptable change as a percentage of total annual gas billings.

Q2A. Please write down your household's total annual $ gas billings [an estimate is fine]
Q2B. What is the maximum $ dollar amount of change in your family's annual natural gas bill that you can tolerate due to fluctuations in natural gas prices? Write down an approximate dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

CAUTION: SMALL SAMPLE SIZE
RESULTS ARE INTENDED TO BE "DIRECTIONAL" ONLY

Average Estimated Household Natural Gas Billings & the Average Maximum Amount of Change in Annual Natural Gas Billings that Participants Could Live With



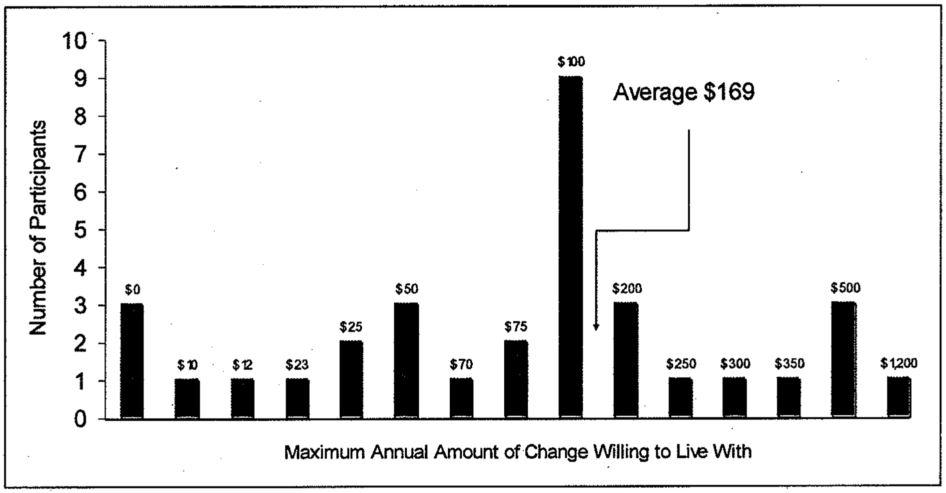
- Overall, the average (estimated) annual natural gas billings for group participants was \$1033, and the maximum amount of change in their annual natural gas billings they were willing to live with was \$169 (which represents 16% of participants' annual natural gas billings).
- As expected, the average estimated annual natural gas billings for the Vancouver Island participants was lower than for the GVRD participants (\$689 vs. \$1287). Accordingly, the average amount of annual change in natural gas billings that Vancouver Island participants were willing to accept was also lower (\$90 versus \$227).
- There was no significant difference in the estimated annual natural gas billings between EPP and Non-EPP participants. Those not on the EPP did not appear to be more tolerant to fluctuations in annual natural gas billings than those on the EPP. Results appear to be the reverse, but this is partly due to the three non-EPP participants who said they wouldn't tolerate any price fluctuations (excluding these three participants the mean increases from \$130 to \$160).
- As expected, those choosing the 100% Hedging Scenario appear to have larger estimated annual natural gas bills than those choosing the Current Hedging Scenario (\$1238 vs. \$1005). Those choosing the 100% Hedging Scenario also appear to have a lower willingness to tolerate volatility in the annual natural gas billings than those choosing the Current Hedging Scenario (\$44 vs. \$186).
- As a percentage of their total annual gas bill, those choosing the 100% Hedging Scenario would only accept a maximum change of 4% over the year, which is lower than those choosing the Current Program who would tolerate (on average) a maximum change of 19%.

The following chart shows the *distribution* of participants' answers for the maximum dollar amount of change they could live with per year.

Q2B. What is the maximum $ dollar amount of change in your family's annual natural gas bill that you can tolerate due to fluctuations in natural gas prices? Write down an approximate dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

CAUTION: SMALL SAMPLE SIZE
RESULTS ARE INTENDED TO BE "DIRECTIONAL" ONLY

Maximum $ Dollar Amount of Change in Annual Natural Gas Billings that Participants Could Live With [Distribution of Responses]

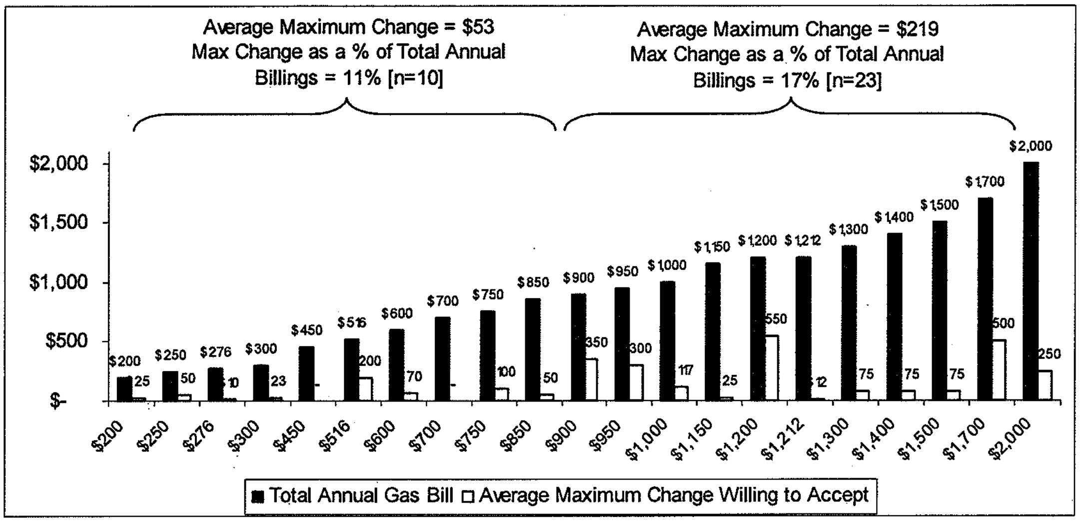


With respect to the maximum change in the annual natural gas billings that participants were willing to live with, results show that:

- The minimum amount was $0 and the maximum was $1200
- The average amount was $169
- The most frequently given response was $100 (nine participants)
- Just under one-quarter of participants expressed amounts of $25 or less;
- 70% of participants expressed amounts of $100 or less

The maximum dollar amount change in annual natural gas billings that participants are willing to live with tends to increase as the total annual billings for the household increases. This is demonstrated in the following chart.

Estimated Annual Household Natural Gas Billings & the Maximum Amount of Change in Annual Natural Gas Billings that Participants Could Live With



The above chart shows participants' total estimated annual natural gas billings along with the maximum change in their annual gas billings they could live with.

- Results show that for total annual natural gas billings of less than $900, the average amount of change participants could live with in their annual gas billings was $53 (or 11% of total annual billings under $900).
- For total annual natural gas billings of $900 or more, the average amount of change per year participants could live with was $219 (or 17% of total annual billings of $900 and over)

5.0 Equal Payment Plan

- The benefits of the EPP were that it was helpful for budgeting purposes and that there were no monthly surprises on the natural gas bill.
- Drawbacks of the EPP were that there was no interest paid on the pre-paid money (though another commented that Terasen Gas didn't charge interest either so that it all balanced out).
- Reasons for not going on the EPP were that participants wanted to see and monitor their actual gas consumption; that they liked having lower payments in summer to better match their income flow; or they wanted to monitor their efforts to conserve energy.

Appendices

Appendix A: Focus Group Discussion Guide

Natural Gas Price Volatility Focus Groups
February 7th & 8th, 2005 - Draft 6

Introduction

- Who is Western Opinion Research
- Importance of group / Feedback from all participants
- Don't all talk at once
- The moderator does not have any answers, just questions
- There are only right answers
- Have fun
- Video/audio taping -And we have observers
- Let's start by going around the room with brief intros

General Natural Gas Observations - Warm-up

1. The discussion this evening will be about different aspects and issues regarding residential natural gas services. I would like to start off by discussing briefly the natural gas bill you receive each month. What are your general thoughts? [HAND OUT EXAMPLE NATURAL GAS BILLS]

2. What are some top-of-mind impressions about your household natural gas service----likes and dislikes? IF NECESSARY PROMPT WITH... What about pricing?

   Are people aware that the bill charges can be broken down into separate charges?
   Is it clear to you what the various items on the bill are?
   [TRY TO ISOLATE THE GAS COMMODITY PORTION ALONG WITH OTHER ELEMENTS AS NOTED BELOW]
   LOOK FOR HOW CUSTOMERS DESCRIBE THE VARIOUS PARTS OF THE BILL - WHAT LINGO DOES CUSTOMER USE?
   SHOW PARTS OF THE BILL ON FLIPCHART

   - Commodity (Cost of the Gas)
   - Delivery Charge (Charge from Terasen Gas for delivering Gas to customers)
   - Taxes

Price Fluctuations

3. One of the concerns expressed about natural gas services was price fluctuations or price volatility (that is, the ups and downs of prices). What do you think is behind or is causing price fluctuations in your natural gas bill? [FLIPCHART - BUILD LIST AS NOTED BELOW]
   - Weather
   - Economy
   - International Events
   - Production and Transportation Costs

4. Is there a part of your natural gas bill you think is most responsible for the price changes you experience throughout the year? [REFER TO EARLIER BILL COMPONENT DISCUSSION IF NECESSARY]

5. How do you determine that a change in your monthly bill is as a result of an increase or a decrease in the price of natural gas as opposed to a change in your own usage or consumption of natural gas? (e.g. Seasonal/cold weather)?
[LISTEN FOR MEDIA MENTIONED]

   Do you automatically assume any change in billing amount is related to price and not to usage?

   In the past, have you reviewed your bill to determine in which part of the bill the increase is occurring? Was this recently? What did you determine?

6. In your view, how often does your natural gas bill fluctuate as a result of natural gas price changes?
WHERE APPROPRIATE MENTION COST OF GAS IS A FLOW THROUGH CHARGE. IN OTHER WORDS, TERASEN GAS CHARGES CUSTOMERS <u>AT COST</u> FOR GAS (NO PROFIT)
TERASEN GAS DOES MAKE A PROFIT FROM THE DELIVERY PORTION OF THE BILL, BUT THIS IS REGULATED BY THE BC UTILITIES COMMISSION

Awareness of Measures to Control Price variations

7. Is Terasen Gas doing anything to try to control these price fluctuations? What steps is Terasen Gas taking? [PROBE]

Quarterly Price Adjustments

CLARIFICATION FOR PARTICIPANTS: So we are all clear on this, in the remainder of the group when I want to refer to the <u>cost of the gas</u> but <u>not any other charges</u> that may appear on your bill, I will call this **"Gas Commodity"** charges.

8. Currently Terasen Gas reviews the natural gas commodity charge (that is the price for the natural gas) every 3 months. How many of you were aware of this?

READ If Terasen Gas has paid more or less for the natural gas than it has collected from customers, this review may lead to an increase or decrease in the commodity charge.

Do you think that making a price adjustment every three months is a good approach to take?
IF PARTICIPANT ASKS WHAT OTHER FREQUENCY OF PRICE CHANGE, CAN USE 'EVERY YEAR/ANNUALLY'.

Hedging Program

Like many products and services, the price that Terasen Gas pays for natural gas can go up or down, and this can increase or decrease the Gas Commodity Charges that customers pay on their Natural Gas Bill.

Terasen Gas operates a "Hedging Program" on behalf of its natural gas customers to moderate or smooth out the degree of natural gas price volatility or price fluctuations. The result of this works almost like different mortgage rate plans: Variable Rate and Fixed Rate Mortgages.

For example, the interest rate you pay on a variable rate mortgage can go up or down, depending on the market. For people who are tolerant to changes in interest rates, this can save them money in the long run.

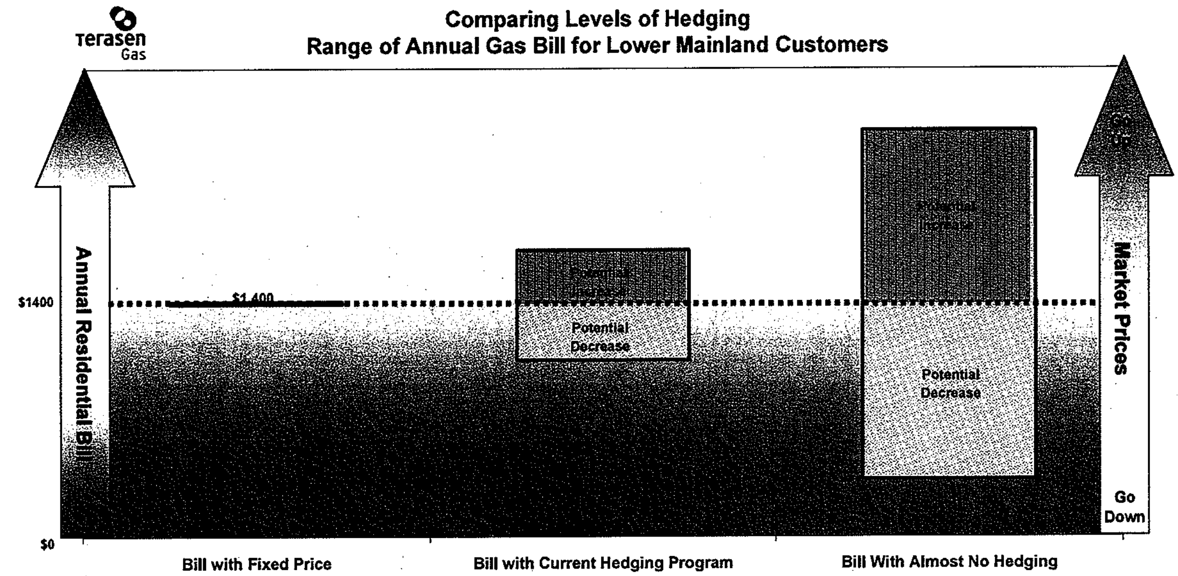
For people who are less tolerant to changes in interest rates or who want to pay the same amount for their mortgage payment each month, they can choose to have a fixed rate mortgage, where the interest rate remains fixed for a period of time. If the market interest rate goes up, they benefit from a fixed interest rate. However, if the market interest rate goes down, they are tied to the fixed interest rate.

- Fixed Rate works better if prices go up
- Variable Rate works better if prices go down

Fixed rate mortgages eliminate price fluctuations. In a similar way, Terasen Gas strategy is to manage price fluctuation to reduce, but not completely eliminate, gas price fluctuations

Let me describe this in more detail.

HANDOUT 1


Terasen Gas
Comparing Levels of Hedging
Range of Annual Gas Bill for Lower Mainland Customers
Annual Residential Bill
$1400
$0
$1,400
Potential Decrease
Potential Decrease
Market Prices
Go Down
Bill with Fixed Price
Bill with Current Hedging Program
Bill With Almost No Hedging

SCENARIO 2: Current program

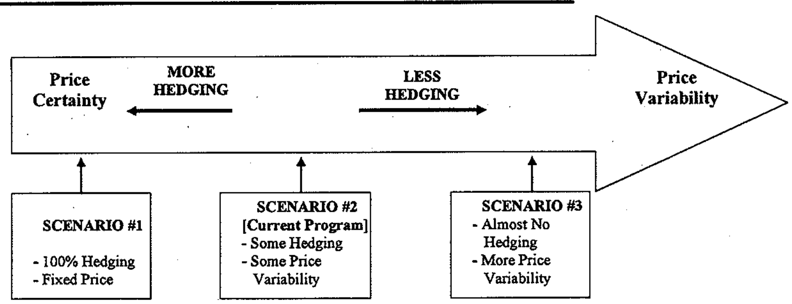
9. What is your understanding of the current program to manage price fluctuations as I have just described it? What are the positive aspects? What are the trade-offs?

Is this a worthwhile program for Terasen Gas to have on behalf of its natural gas customers?

Now I would like to discuss with you two possible modifications to the current hedging program that I just described.

SCENARIOS 1 AND 3 - DESCRIBE ALTERNATIVE PROGRAMS

CIRCULATE HANDOUT #2 – ARROW DIAGRAM



Q1A. Please check which one of the three hedging program approaches you *personally* would prefer:
CHOOSE ONE
☐ Scenario 1 (fixed price),
☐ Scenario 2 (current)
☐ Scenario 3 (more variable price).

Q1B. Please write down the main reasons why you would prefer that Terasen Gas utilize the approach you selected above.

___

___

Q2A. Please write down your household's total annual $ gas billings [an estimate is fine] RECORD ANSWER HERE → $

Q2B. What is the maximum $ dollar amount of change in your family's annual natural gas bill that you can tolerate due to fluctuations in natural gas prices? Write down an approximate dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

RECORD ANSWER HERE → $

10. **Before I hear your views**, I would like you to write down for me on the sheet of paper which of the three hedging program approaches you personally would prefer: **scenario 1** (fixed price), **scenario 2 (current),** or **scenario 3 (more variable price).** In addition, please write down the primary reason (s) why you would prefer that Terasen Gas utilize the approach you selected.

11. Then indicate a) your HH's current total annual natural gas billings and b) what the maximum amount of change in your family's annual natural gas bill that you could live with due to fluctuations in natural gas prices? Write down for me a dollar amount that, within this amount as a rate payer, you can live with and expect, given that natural gas is a product bought and sold on the open market.

Start with your current ANNUAL bill amount (approximately). What then would be an acceptable change to this annual amount that you can tolerate?
IF NECESSARY: CHANGE IS INCREASE OR DECREASE

[DISCUSS ITEMS #10 AND #11 IN GROUP]

Do you consider your gas cost to be a significant % percent of your total household expenditure?

Do you know what % of your total household expenditures that your gas bill represents?

EPP

12. [*NON-EPP GROUPS*] What do you know about the Equal Billing Payment Plan? How does it work? [FLIPCHART] In your opinion what are the benefits?

13. Drawbacks? [FLIPCHART]

14. Why aren't you on the Equal Billing Payment Plan?

15. [*EPP GROUP*] All of you are on the EPP. What in your opinion are the main benefits of this plan? [FLIPCHART] What would you say is the primary reason for your choosing this plan? What about the drawbacks?

16. How does the EPP manage changes in the price of natural gas? When are the adjustments made to the cost of the plan?

17. Do you think that EPP is a good program for households to use to manage natural gas price fluctuations? (for helping to manage your monthly household budget expenses?)

Wrap-up

Any last thoughts
Thank you for your help this evening
Good-bye

Appendix B: Pre-Group Handout Questionnaire

First Name: ___________

While waiting for the research discussion group to commence, please complete the following brief questionnaire. The hostess will pickup the completed questionnaires before the discussion begins.

FIRST, PLEASE ANSWER THESE QUESTIONS ABOUT THE <u>LAST YEAR</u>.

1. As you think back over the <u>Last year</u>, how would you describe the price changes that have occurred for each of the products and services listed below?

   Please √ the appropriate box.

	Increased significantly	**Increased slightly**	**Stayed the same**	**Decreased slightly**	**Decreased significantly**	***Don't know***
Electricity						
Phone						
Gasoline						
Natural Gas						
Fruits & Vegetables						

2. Of the above-listed products and services that have increased in price over the last year, which <u>one</u> of the increases concerns you the most? ____________________

3. Sometimes there are a number of ups and downs in the prices of products and services within any given year. We will call these ups and downs **price fluctuations** or **price volatility.**

   a) Over the last year, which <u>one</u> of the products and services listed above has shown the greatest price fluctuation or greatest price volatility? __________

   b) And over the last year, which <u>one</u> has shown the least price fluctuation or least price volatility? ______________

Continue on page 2

NOW, PLEASE ANSWER THE FOLLOWING QUESTIONS ABOUT NEXT YEAR.

4. As you look ahead over the next year, how would you describe the price changes that you expect will occur for each of the products and services listed below?

Please √ the appropriate box.

	Will increase significantly	Will increase slightly	Will stay the same	Will decrease slightly	Will decrease significantly	*Don't know*
Electricity						
Phone						
Gasoline						
Natural Gas						
Fruits & Vegetables						

5. Of the above-listed products and services that you expect will increase in price over the next year, which one of the expected increases concerns you the most?

   ____

6. As noted earlier, sometimes there are a number of ups and downs in the prices of products and services within any given year. Here we will call these ups and downs **price fluctuations** or **price volatility.**

   a) Now, looking ahead over the next year, which one of the products and services listed above do you think will show the greatest price fluctuation or greatest price volatility? ____________________

   b) And, over the next year, which one do you think will show the least price fluctuation or least price volatility? ____________________

Thank you. The hostess will collect your completed questionnaire.

TERASEN GAS INC.

RESIDENTIAL CUSTOMER PRICE VOLATILITY PREFERENCE SURVEY

FEBRUARY 2005

Final Report

April 15, 2005

WESTERN OPINION RESEARCH INC.

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Executive Overview

Introduction

In February 2005, Terasen Gas engaged Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:
- 2 Groups with GVRD[1] residents (one group on the EPP[2], one group not on the EPP)
- 2 Groups with CRD[3] residents (one group on the EPP, one group not on the EPP)

The groups were held on February 7th and 8th, 2005. Both groups were moderated by Brian Owen.

Phase 2 of the project consisted of a telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

Data collection for the telephone survey occurred from February 18 to March 7, 2005. This report summarizes the results of Phase 2 of the research. Phase 1 of the research was used to identify the range of opinions on the subject and aid in the development of a questionnaire. The objective of Phase 2 was to quantify the findings from the qualitative phase, and to examine important differences in sub-groups.

Key Findings

1. A sizeable proportion (71%) of respondents expressed concern about future fluctuations in the price of natural gas. Respondents tended to be more concerned about future price fluctuations in the price of gasoline and natural gas, than they were about price fluctuations in the cost of telephone or electricity.

   - On a scale of one to ten, with ten being the highest level of concern, 71% of respondents expressed a higher level of concern about future increases in the price of natural gas (rated 7 or more out of ten).
   - While this was not as high as expressed for gasoline (75% rated 7 or higher), it was markedly higher than for electricity (58%) or telephone (40%).

[1] Greater Vancouver Regional District
[2] Equal Payment Plan
[3] Capital Regional District (Victoria)

2. Frequent reasons for concern about future natural gas price fluctuations were that it made *budgeting more difficult*, that respondents *didn't like having to pay more for natural gas*, that *natural gas is a necessity* or concern that *world market forces affected prices*.

   - Most frequently, 34% of respondents said that changing prices would make it more difficult to budget for natural gas expenses, particularly for those on fixed incomes.
   - Other reasons primarily related to concerns over having to pay more for natural gas. This included responses such as: "concerns over rising natural gas prices" (21%), that respondents "didn't like having to pay more for natural gas" (11%), or that "natural gas prices were considered too high already" (10%).
   - The fact that natural gas was viewed as a "necessity" (14%) was another theme that emerged. Participants said they used natural gas to heat their houses, water heaters and appliances. Because of the importance of natural gas in these daily aspects of life, respondents expressed concern over the potential for future price increases.
   - A few (8%) expressed concern over the world market being the driving force behind natural gas price fluctuations. Concerns in this respect related to external factors influencing an important commodity. A related theme was that Canadians should not have to pay market prices for natural gas because natural gas is extracted in Canada.
   - Finally a small percentage (5%) attributed rising natural gas prices to a perceived "monopoly status" of Terasen Gas. The perception was that in the absence of competition, Terasen Gas could charge whatever it wanted for natural gas.

3. Just under half (45%) of residential customers said they were aware that Terasen Gas passes on the cost of natural gas it buys at cost to customers. While a sizeable minority of residential customers says they are aware of this fact, it would appear that there is room to increase awareness on this measure.

4. Customers are generally aware that supply and demand for natural gas are the key drivers of natural gas pricing.

   - Generally, there was a fairly high level of knowledge among residential customers that supply (30%) and demand (42%) and world market (14%) forces are key drivers of natural gas pricing. Other factors cited by respondents included political factors (9%), the weather (7%), the economy (6%) and corporate profits /greed (8%) or oil producer profits (4%).

5. Typically, customers attribute month-to-month changes in their natural gas bill to changes in *consumption* rather than changes in the *price* of natural gas.

   - Largely, respondents were of the perception that month-to-month changes in their natural gas bill are due to changes in their consumption (52%) rather than price (28%), though a small proportion insisted it was due to both (8%). A similar result was found in the Phase 1 Focus Groups, in which customers did not automatically attribute changes in their gas bill to rate changes, but rather to changes in consumption.

6. Awareness of hedging activities by Terasen Gas to manage natural gas price fluctuations is very low among residential customers.

   - A third (33%) of residential gas customers said they were aware of measures or programs operated by Terasen Gas to smooth out natural gas price fluctuations. However, when asked to *describe* measures or programs that Terasen Gas operates to manage natural gas price fluctuations, very few customers were able to provide accurate answers.
   - Only 1% of all respondents could accurately cite activities by Terasen Gas to manage price fluctuations.

7. When informed about hedging activities undertaken by Terasen Gas to manage fluctuations in natural gas prices, most residential customers (66%) were in support of this activity. Reasons for not supporting hedging activities generally revolved around the following: a) a lack of knowledge about how the Hedging Program works; b) general cynicism about how natural gas rates are established or the belief that natural gas rates are already too high; and c) mistrust of the Program or of Terasen Gas.

   - While 66% were in support of the current Hedging Program, this support tended to be fairly soft with a higher proportion of respondents being "somewhat" supportive (41%) than "strongly" (25%) supportive. Another 9% of respondents said they were "neutral" towards the program while 11% said they "didn't know" or "refused" (1%). Relatively few respondents (13%) said they were opposed to the program.
   - A number of reasons were cited for opposing the current Hedging Program, including the lack of knowledge about how the Program works (23% didn't know & 5% said they needed more information), general cynicism about how natural gas rates are established (13%), that natural gas rates are already too high (12%), mistrust of the Program (10%) or mistrust of Terasen Gas (8%).
   - Other less frequent reasons for opposing the Program included: a) preference for a fixed rate for natural gas (9%), b) concerns that natural gas prices increase with hedging (8%), and c) the belief that natural gas should only be purchased as needed (7%).
   - As might be expected, the primary reasons for neither supporting nor opposing the Program (i.e. neutral or don't know responses) were: a) respondents didn't know enough to respond (41%), b) they needed more information (23%), or c) they didn't fully understand the Program (5%).

8. The general "stated" preference by residential customers for natural gas hedging activities is towards the *current hedging program* and leaning slightly towards *more hedging* activities rather than less hedging.

   - Results show that 44% of respondents preferred the Current Hedging Program while 28% said they preferred more hedging and 20% less hedging. This would indicate that the general preference towards hedging activities is towards the current hedging program and leaning towards more hedging activities than less hedging. Similar results were received in the phase 1 focus groups with residential customers.

9. The maximum change in annual natural gas billings that customers could live with in a year *averaged* $340. Excluding amounts over $1500 the average was $234; and excluding amounts over $1000 the average was $144.

   The median[4] amount of change in annual natural gas billings that customers could live with in a year was $100 for all responses. Excluding amounts over $1500 the median remained unchanged at $100 while excluding amounts over $1000 reduced the median amount to $74.

   As a percentage of respondents' estimated annual natural gas billings, the maximum amount of increase that respondents could live with averaged 27% for the total sample. Noteworthy is that this proportion tended to decrease as respondents' annual billings increased.

   - The *minimum* amount was $0 (16%), while the *maximum* was $4000.
   - Among participants who provided dollar amounts (including $0), one-quarter said $0/no increase; just over one-half said amounts of $100 or less, and 70% said amounts of $240 or less.
   - Customers' annual estimated natural gas billings typically fell between $500 and $1800 and averaged $1262 per year. As expected, costs were higher in the Interior ($1281) and Lower Mainland regions ($1299) than for Vancouver Island ($956).
   - Although the maximum amount of increase that respondents could live with averaged 27% of their total annual natural gas billings for the total sample, this proportion tended to decrease as respondents' annual billings increased. Respondents having somewhat smaller annual gas billings (eg $900 or less) tended to be willing to accept higher proportions (eg 38% - 48%) while those with higher annual gas billings (eg >$1300) tended to be willing to live with somewhat lower proportions (eg 15% to 27%).
   - Those who preferred the Current Hedging Program gave significantly lower annual average amounts of change that they could live with ($302) than those preferring more hedging ($378) or less hedging ($405). As a percentage of total annual estimated natural gas billings, respondents preferring the Current Program also cited lower percentages (24% vs. 30-33%). On the basis of these results it would appear that respondents preferring the Current Hedging Program are less willing to accept change in natural gas costs than those preferring less hedging or more hedging.

10. As the potential for savings increases or decreases, respondents were not willing to increase or decrease the maximum amount of increase in annual natural gas billings they were willing to tolerate. While customers could articulate a maximum increase in their natural gas billings they were willing to live with, it was difficult for many to consider or understand changing that amount to receive the "potential" benefit of lower prices.

    - Results show that to a large extent, respondents' answers remained constant, regardless of the amount of potential decrease in their annual billings. In other words,

[4] the middle value in a distribution, above and below which lie an equal number of values.

respondents' answers remained the same given four different potential savings scenarios: $600, $400, $200 and $100.

- Perhaps this is because residential consumers of natural gas do not think in terms of the potential for savings on their natural gas bill, but rather the maximum amount of change they are willing to live with.

Conclusions and Recommendations

Based on the results of the focus groups and survey of residential customers, the following conclusions and recommendations emerge.

1. A sizeable proportion (71%) of residential customers expressed a higher level of concern over future natural gas price fluctuations (7 or higher out of a possible 10). This stems from potentially having to pay more for a household "staple", which is a concern for people on fixed incomes, and those who don't want to pay more for natural gas.

2. A sizeable minority of customers are aware that Terasen Gas passes on the cost of natural gas that it buys to customers at cost, that is, with no added markup or charges (45%); however, most are not aware of this fact. In the event of increased volatility in the price of natural gas, it would be advantageous for Terasen Gas to increase awareness of this fact among residential customers.

3. The fact that most respondents attribute changes in their natural gas bill to changes in consumption (52%) rather than natural gas rates (28%) indicates that at present, natural gas volatility is not a big issue with customers. This is supported by focus groups with customers who raised few concerns about current natural gas rates, or natural gas price volatility. However, based on customers' stated level of concern over the possibility of future natural gas price fluctuations, Terasen Gas should continue with hedging practices to buffer against such possible volatility.

4. Awareness of hedging activities by Terasen Gas to manage natural gas price fluctuations is very low among residential customers but when explained to them, two-thirds are supportive of this practice. We hypothesize that the reason why support for current hedging practices was not higher is mainly because respondents required more information than could be provided in the short telephone interview.

5. The general "stated" preference by residential customers for natural gas hedging activities is towards the current hedging program (44%), and leaning slightly towards more hedging activities (28%) than less hedging (20%). This would indicate that if any changes were made to Terasen Gas' overall hedging strategy, it would be towards more rather than less hedging.

6. The maximum change in annual natural gas billings that customers could live with in a year *averaged* $340; though it should be noted that this figure was inflated by a relatively small number of large dollar amounts. Excluding amounts over $1500 the average decreases to $234; and excluding amounts over $1000 the average decreases to $144. Noteworthy is that 70% of customers (citing dollar amounts) gave amounts of $240 or less. On the basis of these findings the overall average of $340 overstates the preferred price volatility of a substantial proportion of customers. If a figure must be chosen to

reflect the diverse preferences of <u>all</u> customers we suggest using the median for the entire sample ($100) or perhaps the mean excluding amounts over $1000 ($144).

7. The maximum amount of increase that respondents could live with averaged 27% of their total annual natural gas billings for the total sample. Noteworthy, is that this proportion tended to *decrease* as respondents' annual billings *increased*. That is, respondents having somewhat smaller annual gas costs tended to be willing to accept higher "proportional amounts" (e.g. 38%-48%) while those with higher annual gas billings tended to be willing to live with somewhat lower proportions (15%-27%). A hypothesis to explain this finding is that those with lower annual natural gas billings may be willing to accept a proportionately higher amount of price volatility because the dollar amount of change at stake is smaller, and so poses less of a potential disruption to household budgets.

8. Based on this research, the potential for receiving greater savings on natural gas costs does not affect customers' willingness to accept more or less fluctuation in their annual natural gas bill.

Foreword

Background and Research Objectives

In February 2005, Terasen Gas engaged the services of Western Opinion Research Inc. to conduct a two-phased study with residential customers of Terasen Gas. The purpose of the research is to assess and measure the perceptions and preferences of customers as they relate to natural gas price volatility.

More specifically, the objectives of the research are to:

- Define customers' level of understanding regarding natural gas rates – including their components and how rates are set.
- Understand customers' natural gas price volatility preferences and determine if price points exist where customers are willing to accept more volatility in the form of rate variability and where they desire less volatility through rate stability.
- Use the results to revise Terasen Gas' price-risk management hedging strategy as appropriate.

Phase 1 consisted of four focus groups with residential natural gas customers as follows:

- 2 Groups with GVRD[5] residents (one group on the EPP[6], one Group not on the EPP)
- 2 Groups with CRD[7] residents (one group on the EPP, one Group not on the EPP)

Phase 2 of the project, consisted of telephone survey of 1000 Terasen Gas residential customers as follows:

- 400 interviews with Mainland customers on the EPP;
- 400 interviews with Mainland customers not on the EPP
- 100 interviews with Vancouver Island customers on the EPP
- 100 interviews with Vancouver Island customers not on the EPP

This report summarizes the results of Phase 2 of the research. Phase 1 of the research was used to identify the range of opinions on the subject and aid in the development of a questionnaire. The objective of Phase 2 was to quantify the findings from the qualitative phase, and to examine importance differences in sub-groups.

---

[5] Greater Vancouver Regional District
[6] Equal Payment Plan
[7] Capital Regional District (Victoria)

Methodology

Phase 1: Focus Groups with Residential Gas Customers

Four focus groups were held with residential gas customers of Terasen Gas on February 7th (GVRD) and 8th (CRD) 2005, as follows:

- 2 Groups with GVRD residents (one group on the EPP, one group not on the EPP)
- 2 Groups with CRD residents (one group on the EPP, one group not on the EPP)

All groups were held in focus group facilities equipped with one-way mirrors for observers, boardroom-style meeting room, and audio-visual recording equipment.

Participants were recruited from customer lists provided by Terasen Gas. Individuals in the household who were most familiar with buying and paying for the household's natural gas were targeted. To encourage participation, a $60 cash incentive was provided. Ten customers were recruited for each group for eight to participate (though up to ten were allowed to participate if they arrived. To be eligible to participate in the groups, participants must have met the following criteria:

- Individuals and the members of their household could not be employed by Terasen Gas or a subsidiary of Terasen Incorporated, a natural gas distributor, producer or natural gas marketer, the media, advertising, or a market research firm;
- They must live within the boundaries of the GVRD/CRD;
- They could not have attended a focus group within the past 12 months; and
- They could not have attended more than five focus groups in the past five years.

To ensure a broad representation of Terasen Gas residential customers, efforts were made to recruit a mix of:

- Males and females;
- Owners and Renters (though the sample was heavily weighted to Owners);
- Those residing in single family as well as multi-family dwellings;
- Residents from a range of communities within the GVRD/CRD; and
- Customers representing a range of age, education, household income and occupational categories.

Phase 2: Telephone Survey of Residential Gas Customers

Phase 2 of the project consisted of a telephone survey of 1000 Terasen Gas residential customers as follows:

Sampling Quota	Sampling Error
400 interviews with Mainland customers on the EPP	+/ - 5.0%
400 interviews with Mainland customers not on the EPP	+/ - 5.0%
100 interviews with Vancouver Island customers on the EPP	+/ - 10%
100 interviews with Vancouver Island customers not on the EPP	+/ - 10%
Total 1000 Residential Terasen Gas Customers	+/ - 3.2%

Results for the total sample of 1000 completed interviews were weighted to be representative of the total population of residential customers in the Vancouver Island, Lower Mainland and Interior regions of BC. The following table shows the weights used.

Region	Weight
Lower Mainland	1.1354
Interior	1.1255
Vancouver Island	0.4705

Throughout the report, survey results are reported in the form of weighted percentages; that is the weighted number of responses as a percentage of the total weighted number of people responding to each question. For significance testing purposes, the *unweighted* base is shown for each chart or table.

The list of customers for the telephone survey was provided by Terasen Gas.

The status of whether or not customers were on the Equal Payment Plan (EPP) was supplied along with the call sample to Western Opinion Research for sample records in the Lower Mainland and Interior regions. On Vancouver Island, customer's EPP status was not readily available, so respondents were asked whether they were on the EPP in the questionnaire.

Interviews were conducted with the person in the household who was responsible or partly responsible for reviewing and paying for the household's natural gas bills. Data collection occurred from February 18 to March 7, 2005.

A number of survey questions were open-ended; these answers were recorded verbatim by interviewing staff. During data processing, response categories were developed, and the verbatim results numerically coded and tabulated.

Telephone Survey: Detailed Findings

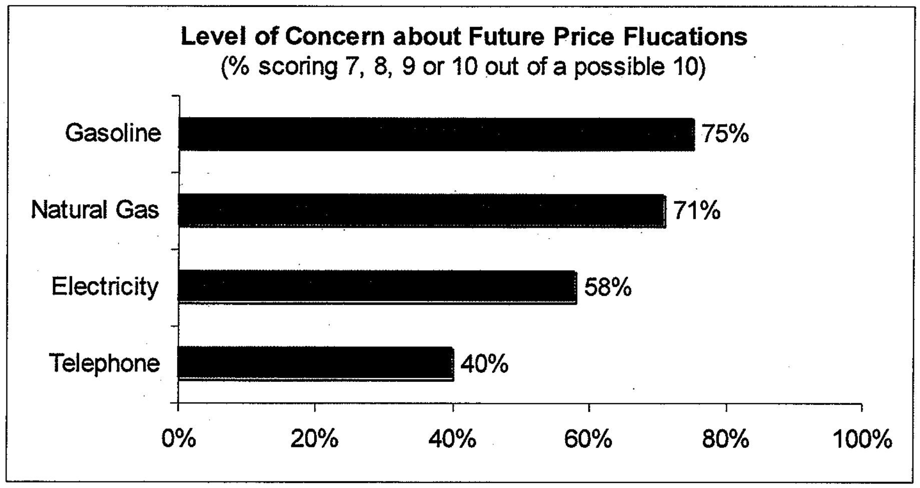
This section presents the results for each question asked of respondents. An interpretive summary of the results follows each chart or table. Sub-group differences in the results are also noted below in bullet form, where they are statistically significant and meaningful.

We begin by examining respondents' level of concern over future price fluctuations among four product or service categories.

1.0 Level of Concern over Price Fluctuations

Concern over Future Price Fluctuations

Q1a. (a-d)	Please tell me how concerned you are about future price fluctuations using a scale from 1 to 10 where 1 is not at all concerned and 10 is extremely concerned?
Base:	Total Unweighted Sample (n=1000)



Results show that respondents tended to be more concerned about future price fluctuations in the price of gasoline and natural gas, than they were about price fluctuations in the cost of telephone or electricity.

On a scale of one to ten, with ten being the highest level of concern, 71% of respondents expressed a higher level of concern about future increases in the price of natural gas (7 or more out of ten). While this was not quite as high as expressed for gasoline (75% 7 or higher), it was markedly higher than for electricity (58%) or telephone (40%).

Sub-Group Differences:

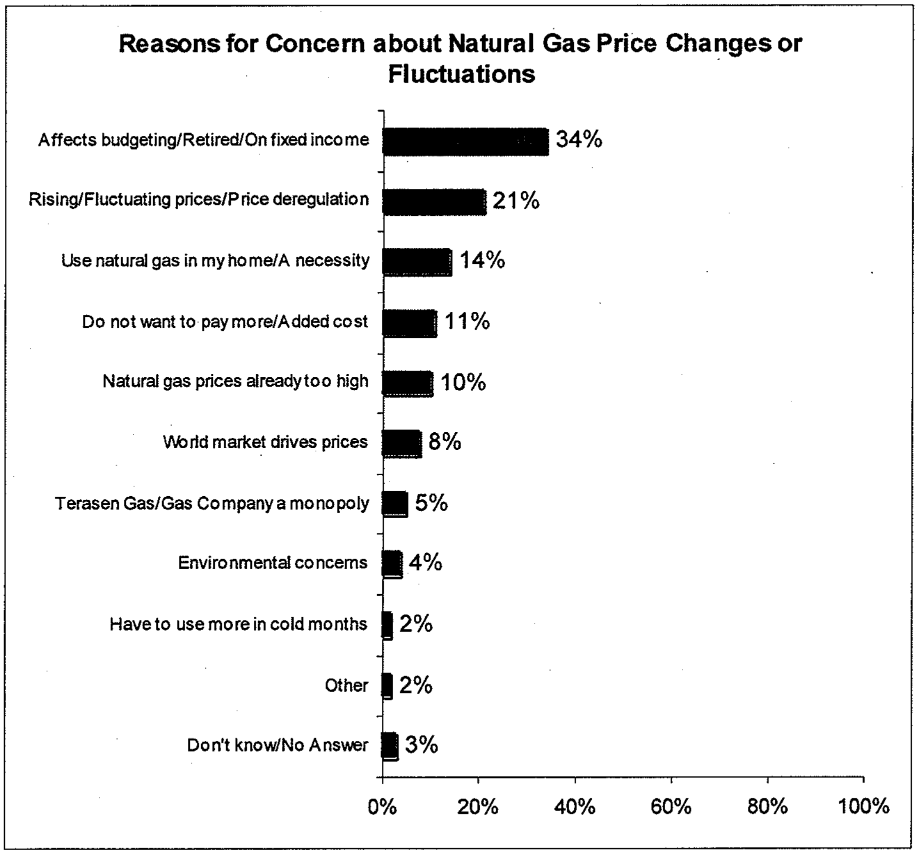
- Respondents with a high level of concern about future price fluctuations for natural gas (defined here as 8 or higher out of a possible 10) also tended to be more concerned about future price fluctuations for electricity (mean 8.0), telephone (mean 6.7) and gasoline (mean 8.8) than other respondents.

- Respondents who attributed changes in their monthly gas bill to *price* rather than consumption had tended to have a higher level of concern about future natural gas price fluctuations than other respondents (mean rating of 8.1 vs. 7.3 out of a possible 10).
- Respondents with higher levels of annual natural gas consumption tended to be more concerned about future natural gas price fluctuations (e.g. Mean rating of 8.0 for those with >$1800 in estimated annual gas consumption vs. a mean rating of 6.9 for those with $500 or less in annual gas consumption).
- Respondents under age 35 tended to be less concerned about future natural gas price fluctuations (mean rating of 6.5) than older respondents (e.g. age 55+ mean rating of 7.7).
- Respondents with some post secondary education or less, tended to be more concerned about future natural gas price fluctuations than those who have completed university (mean rating 7.8 vs. 7.2).
- Respondents with an annual household income of less than $40,000 tended to be more concerned about future natural gas price fluctuations than those with incomes of $100,000 or more.

Reason for Concern about Natural Gas Price Fluctuations

Those who expressed some level of concern about future natural gas price fluctuations (7 or higher out of 10) were asked to explain why they were concerned.

Q1b.	Why are you concerned about natural gas price changes or fluctuations? MULTIPLE RESPONSES
Base:	Unweighted Base IF 7-10 TO Q1a. (n=700)



Most frequently, customers said that changing prices would make it more difficult to budget for natural gas expenses; particularly for those on fixed incomes (34%).

Other reasons were primarily related to concerns over having to pay more for natural gas. This included concerns over rising natural gas prices (21%), that respondents didn't like having to pay more for natural gas (11%), or that natural gas prices were considered too high already (10%).

The fact that natural gas was viewed as a "necessity" (14%) was another theme that emerged. Participants said they used natural gas to heat their houses, water heaters and appliances. Because of the importance of natural gas in these daily aspects of life, respondents expressed concern over the potential for future price increases.

A few (8%) expressed concern over the world market being the driving force behind natural gas price fluctuations. Concerns in this respect related to external factors influencing an important commodity. A related theme was that Canadians should not have to pay market prices for natural gas because natural gas is extracted in Canada.

Finally, a small percentage (5%) attributed rising natural gas prices to a perceived "monopoly status" of Terasen Gas. The perception was that in the absence of competition, Terasen Gas could charge whatever it wanted for natural gas.

Sub-Group Differences:

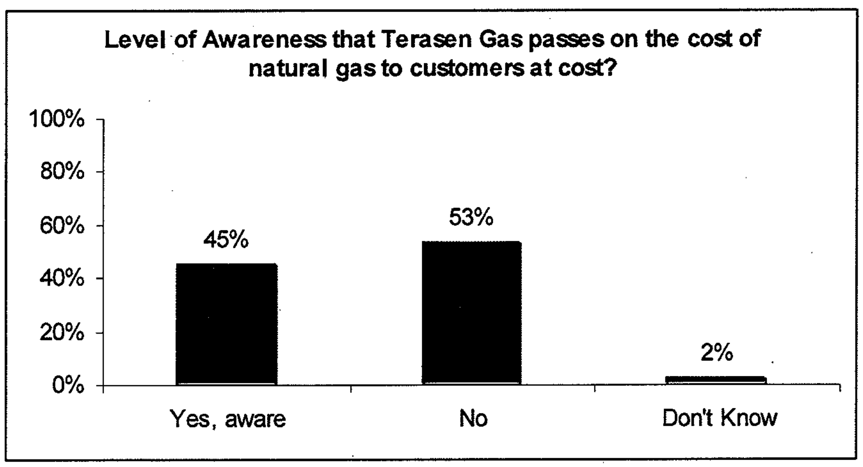
- Respondents aged 55+ were more likely to say that natural gas price fluctuations affected their budgeting than those under 55 (38% vs. 23%)
- More recent natural gas customers (5 years or less) were more likely to say that natural gas price fluctuations are a concern than longer term customers (21-30 years) (22% vs. 10%) because natural gas is viewed as a household "necessity/use gas appliance in home".

2.0 Awareness of Factors Related to Natural Gas Price Fluctations

Earlier, results showed that a substantial proportion of customers were concerned about the possibility of future fluctuating natural gas prices. Given that fluctuating prices could occur, it would be advantageous for Terasen Gas to inform customers that Terasen Gas buys its natural gas on the open market, and passes on the cost of gas to customers with no markup. The following chart shows respondents' level of awareness of this fact.

Awareness that Terasen Gas Passes on the Cost of Natural Gas to Customers at Cost

Q2.	Terasen Gas buys natural gas on the open market and passes on the cost of this natural gas to its customers at cost, that is, with no markup or added charges. Were you aware of this?
***Base*:**	Total Unweighted Sample (n=1000)



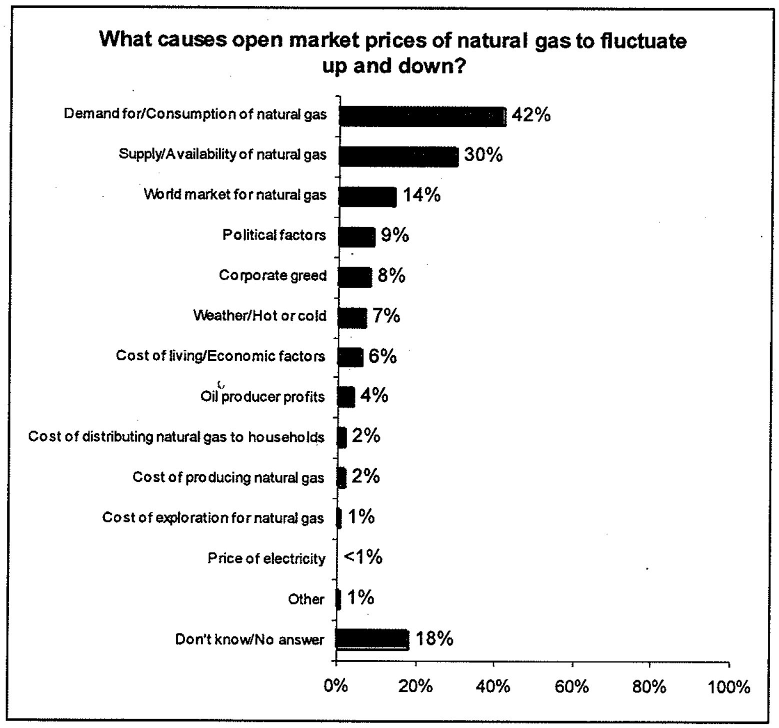
Results show that just under half of residential customers (45%) were aware that Terasen Gas passes on the cost of natural gas at cost to customers. While a sizeable minority of residential customers *said* they were aware of this fact, it would appear that there is room to increase awareness on this measure.

Sub-Group Differences:

- Those under age 34 were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (71% aware) than those age 55+ (51% aware)
- Those with lower annual household incomes (<$20,000) were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (67%) than other customers (50%).
- More recent natural gas customers (5 years or less) were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (72%) than longer term customers (11+ years) (47%)
- Males were more likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (58%) than females (34%)
- Those on Vancouver Island were less likely to be aware that Terasen Gas passes on the cost of natural gas at cost to customers (20%) than respondents in other regions (47%)

Awareness of Factors Causing Natural Gas Price Fluctuations

Q3.	What do you think causes the open market price of natural gas to fluctuate up and down? MULTIPLE RESPONSES
Base:	Total Unweighted Sample (n=1000)



Generally, there was a fairly high level of knowledge among residential customers that supply (30%) and demand (42%) and world market (14%) forces are key drivers of natural gas pricing.

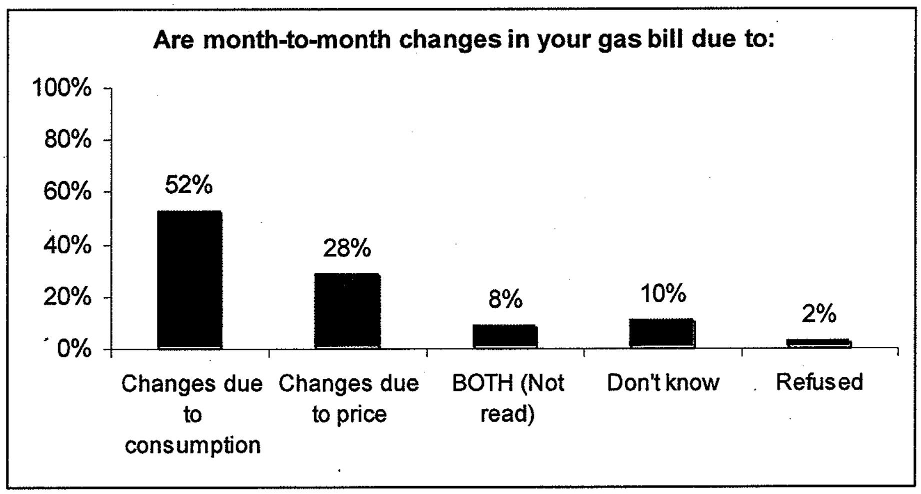
Other factors cited by respondents included political factors (9%), corporate profits /greed (8%), the weather (7%), the economy (6%) and or oil producer profits (4%).

Sub-Group Differences:

- Those with a high school education or less were more likely to say they "didn't know" what causes the open market price of natural gas to fluctuate (26%) than other respondents (13%)
- Those with income levels of less than $20,000 were more likely to say they "didn't know" what causes the open market price of natural gas to fluctuate (41%) than respondents with higher income levels (16%)

Are Changes in Monthly Natural Gas Bill Automatically Attributed to Changes in Rates?

Q4.	Are month-to-month changes in the amount of your household's natural gas bill typically due to changes in the price of natural gas, or due to changes in your household's consumption of natural gas?
Base:	Total Unweighted Sample (n=1000)



Largely, respondents were of the perception that month-to-month changes in their natural gas bill were due to changes in their consumption (52%) rather than due to price (28%) though a small proportion insisted it was due to both (8%). A similar result was found in the Phase 1 Focus Groups, in which customers did not automatically attribute changes in their gas bill to rate changes, but rather to changes in consumption.

Sub-Group Differences:

The following groups were more likely to attribute changes in their monthly gas bill to price:

- Respondents with a higher level of concern (defined here as 8 or higher out of a possible 10) about future natural gas price fluctuations (33%) as compared to those with lower levels of concern (22%).
- Respondents with a high school graduation or less (34%) as compared to others (24%)
- Those aged 65 or older (36%) versus younger respondents (19%)

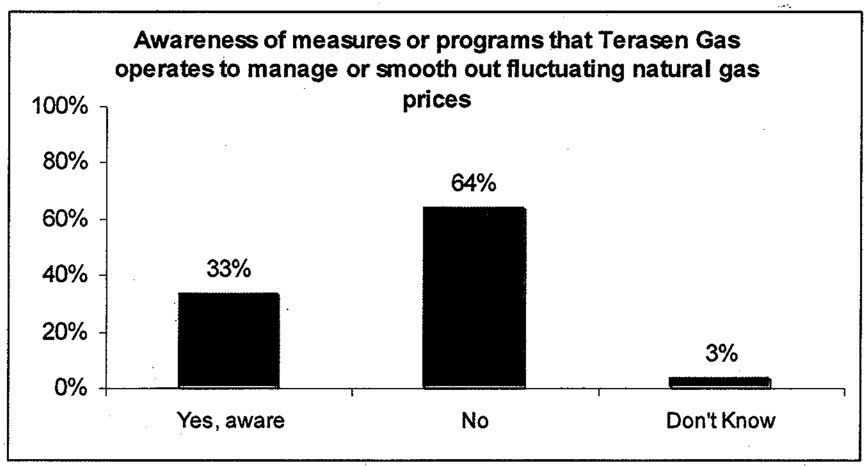
- Those with annual household incomes of less than $20,000 (38%) versus those with incomes of $40,000 or higher (23%)
- Natural gas customers for more than 30 years (34%) versus shorter term customers (22%)
- Respondents living in the Lower Mainland (28%) or Interior (31%) versus those living on Vancouver Island (18%)

3.0 Terasen Gas Natural Gas Hedging Program

Having now defined the level of residential customer awareness of a number of natural gas price fluctuation related issues, questions were posed about Terasen Gas' Natural Gas Hedging Program. The following graph shows respondents awareness of this Program, unaided.

Awareness of Terasen Gas Programs to Manage Fluctuating Natural Gas Prices

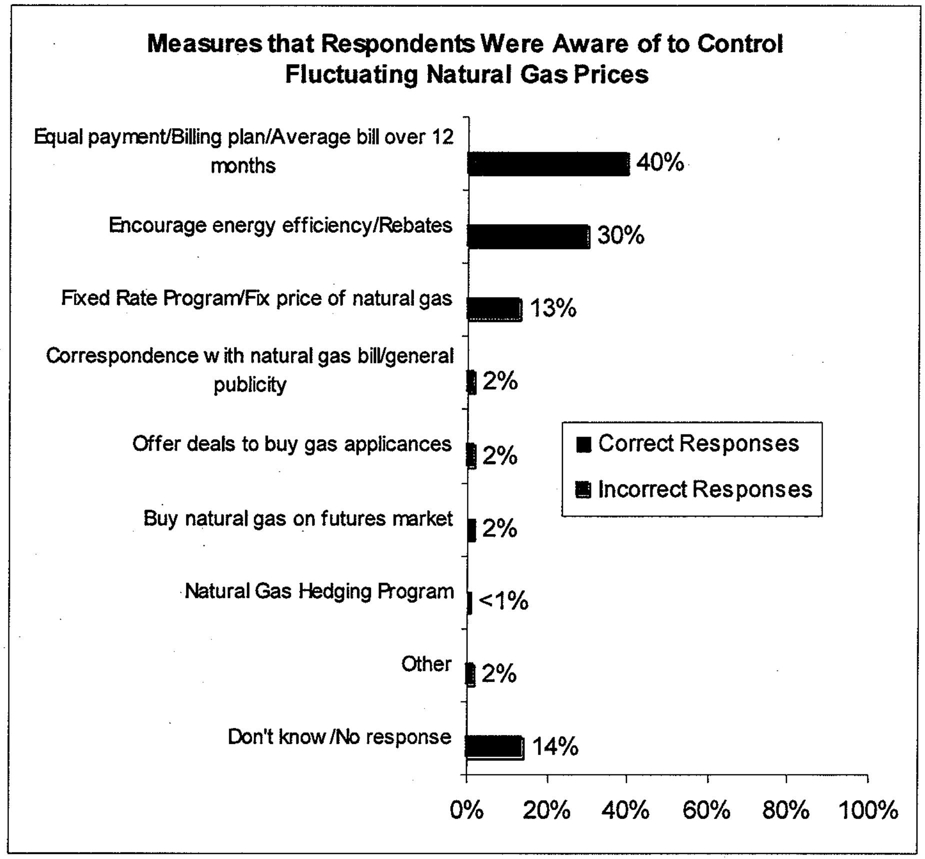
Q6.	Are you aware of any measures or programs that Terasen Gas operates, or that it may operate on behalf of its customers to manage or smooth out fluctuating natural gas prices?
Base:	Total Unweighted Sample (n=1000)



A third (33%) of residential gas customers said they were aware of measures or programs operated by Terasen Gas to smooth out natural gas price fluctuations.

In fact, the results to the following question will demonstrate that awareness is much lower.

Q6.	What measures are you aware of? MULTIPLE RESPONSES
Base:	Unweighted Base IF YES TO Q5 (n=308)



When asked to describe measures or programs that Terasen Gas operates to manage natural gas price fluctuations, very few customers were able to provide accurate answers.

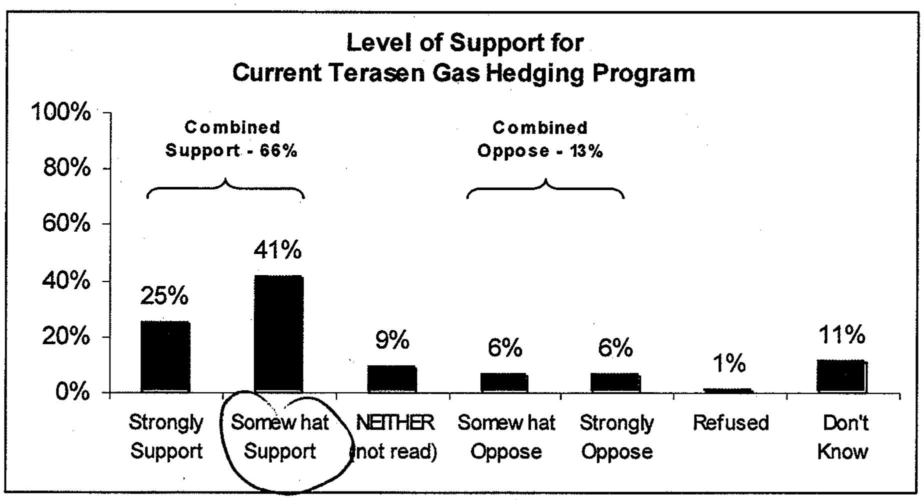
Among the third of respondents who *said* they were aware of such measures, only two percent could give correct answers; which included "buying gas on the futures market" (2%), or "natural gas hedging activities" (<1%). As a percent of *all respondents* in the total sample, only 1% could accurately cite activities by Terasen Gas to manage price fluctuations.

More frequently, participants who *said* they were aware of such measures incorrectly cited the Equal Payment Plan (40%), energy efficiency programs or rebates (30%) or the Fixed Rate Program. Some confusion between aspects of the Equal Payment Plan and changes to natural gas rates was also noted in the Phase 1 focus groups.

Level of Support for Current Terasen Gas Hedging Program

Having now gauged customers' awareness of activities to manage natural gas price fluctuations, respondents were asked if they supported or opposed these activities by Terasen Gas.

> PREAMBLE READ TO RESPONDENTS:
>
> Currently, Terasen Gas does operate a hedging program on behalf of its customers to moderate or smooth out price fluctuations of natural gas purchased on the open market.
>
> It works much like different mortgage rate plans such as Variable Rate and Fixed Rate mortgages. Fixed Rate mortgages eliminate interest rate changes, while Variable Rate mortgages can change with the market. Having a fixed rate is better if interest rates go up because you don't pay more than your fixed mortgage rate. Having a variable rate is better if interest rates go down because you can benefit from declining rates.
>
> In a similar way, Terasen Gas' hedging strategy is used to reduce but not completely eliminate market price fluctuations. In other words, the current hedging program has some variable and some fixed pricing.
>
> Q7a Do you support or oppose Terasen Gas' program to hedge natural gas prices? Would that be strongly or just somewhat?
>
> ***Base*:** Total Unweighted Sample (n=1000)



Results indicate that most residential customers (66%) are in support of the current Hedging Program, but this support tends to be fairly soft with a higher proportion of respondents being "somewhat" in support (41%) than "strongly" (25%) in support. Another 9% of respondents said they were "neutral" towards the program while 11% said they "didn't know".

Relatively few respondents (13%) said they were opposed to the program[8].

Sub-Group Differences:

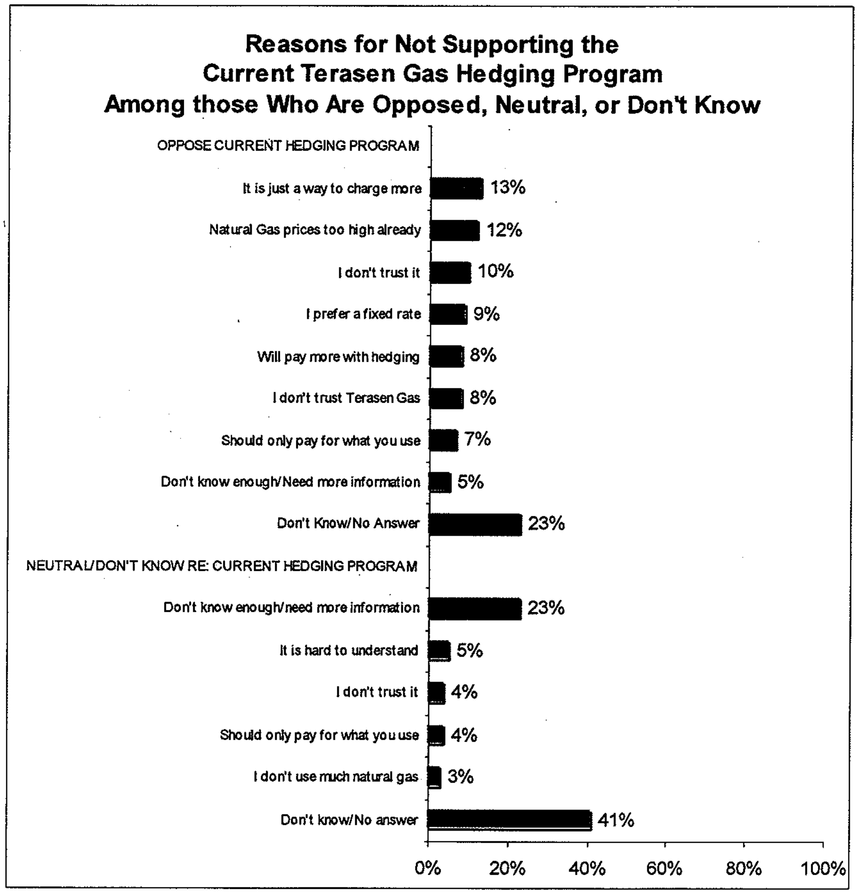
The following groups were identified as being more likely to oppose the Current Terasen Gas Hedging Program:

---

[8] Note: the total percent "opposed" rounds to 13% when combined.

- Respondents with high (defined here as 8 or higher out of a possible 10) levels of concern about future natural gas price fluctuations (16% opposed) versus other respondents (8% opposed)
- Respondents who attributed changes in their monthly gas bill to changes in price (11% strongly opposed) vs. those attributing change to consumption (3% strongly opposed)
- Respondents aged 65+ (15% opposed) versus respondents under age 65 (10% opposed)
- Natural gas customers for more than 20 years (8% strongly opposed) versus customers for 20 years or less (3% strongly opposed).
- Those residing in the Interior (8% strongly oppose) or Lower Mainland (6% strongly opposed) versus those on Vancouver Island (2% strongly opposed)

Q7b.	Why do you say that? MULTIPLE RESPONSES
Base:	Unweighted Base IF OPPOSED, NEUTRAL, DON'T KNOW TO Q7A (n=324) [Most frequent responses shown]



Earlier, about two thirds of respondents said they supported efforts by Terasen Gas to manage price fluctuations while the balance was neutral, didn't know, or were opposed. In a follow up question, respondents not in favour of hedging (i.e. opposed, neutral or didn't know) were asked *why* they answered this way.

A number of reasons were cited for opposing the current Hedging Program but these responses can be grouped into three main categories, including a) the *lack of knowledge about how the Program works to be able to respond* (23% don't know & 5% need more information; b) *general cynicism about how natural gas rates are established* (13%) *or that natural gas rates are already too high* (12%); and c) *mistrust of the Program* (10%) *or of Terasen Gas* (8%).

Other less frequent reasons for opposing the Program included those having a *preference for a fixed rate for natural gas* (9%), those concerned that *natural gas costs more with hedging* (8%) or the belief that *natural gas should only be purchased as needed* (7%).

As might be expected, the primary reasons for neither supporting nor opposing the Program (i.e. neutral or don't know responses) were that respondents *didn't know enough to respond* (41%), that they *needed more information* (23%), or that they *didn't fully understand the Program* (5%).

Sub-Group Differences:

- Those who had completed university were more likely to say they needed more information about the Hedging Program (21%) than those with a high school education or less (10%).

Preferred Natural Gas Hedging Strategy

Next, respondents were read a description of three possible hedging strategies to manage fluctuations in natural gas pricing and then, asked which of the three scenarios they preferred.

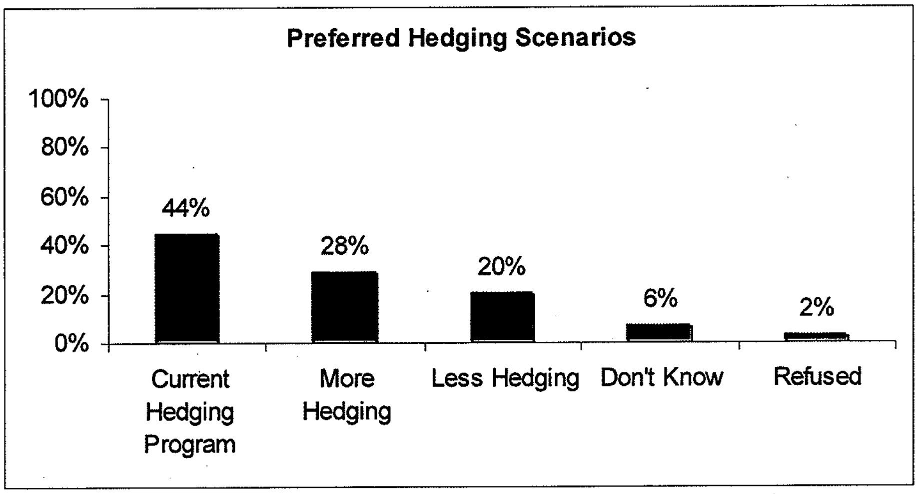
Q8. I am going to read you three different points of view about Terasen Gas' Program to reduce price fluctuations. After I read all three statements, I would like you to tell me which one of the statements is closest to your own view. RANDOMIZE ORDER a-c

a. Terasen Gas should continue its present hedging program to smooth out natural gas price fluctuations.

b. Terasen Gas should hedge less and not smooth out price fluctuations as much as it does. Instead, it should pass on more of the actual ups and downs of market prices to its customers. This would allow customers to benefit more from any drop in natural gas prices, but they may also have to pay more if market prices increase.

c. Terasen Gas should hedge more to further smooth out natural gas price fluctuations. This would provide a fixed price for natural gas which would protect customers from potential increases in the price of natural gas but on the other hand would not allow them to benefit from potential decreases in price.

***Base*:** Total Unweighted Sample (n=1000)



Results show that 44% of respondents preferred the *Current Hedging Program* while 28% said they preferred *more hedging* and 20% said *less hedging*. This would indicate that the general preference for hedging activities is towards the current hedging program, and leaning towards more hedging activities than less hedging. Similar results were received in the phase 1 focus groups with residential customers.

Sub-Group Differences:

The following were more likely to prefer the Current Terasen Gas Hedging Strategy:

- Those with a lower level of concern over future natural gas price fluctuations (defined here as 7 or less out of a possible 10) (55% versus 37% among those with higher levels of concern (8 or higher).
- Those who attribute monthly changes in their natural gas bill to consumption (50% vs. 38% among those who attribute monthly changes in their gas bill to price).
- Respondents on the EPP (49% vs 40% among those not on the EPP).
- Those completing technical/vocational/university (50% versus 38% among those with a high school education or less.
- Those who own their home with a floating rate mortgage (58% versus 42% among those who own their home with no mortgage.
- Those aged 45 – 54 (60% versus 30% among those aged 55+).
- Those with household incomes of $20,000 or more (49% versus 29% among those with less than a $20,000 household income).
- Natural gas customers for 5 years or less (59% versus 40% among customers for 31 or more years).

The following were more likely to prefer More Hedging:

- Those with a higher level of concern over future natural gas price fluctuations (8 or higher out of a possible 10) (32% versus 21% among those with lower levels of concern).
- Those who attribute monthly changes in their natural gas bill to price (33% versus 25% among those who attribute monthly changes in their bill to consumption).
- Those aged 65+ (33% versus 22% among those under 65).
- Those with household incomes of less than $20,000 (42% versus 26% among those with higher household incomes).

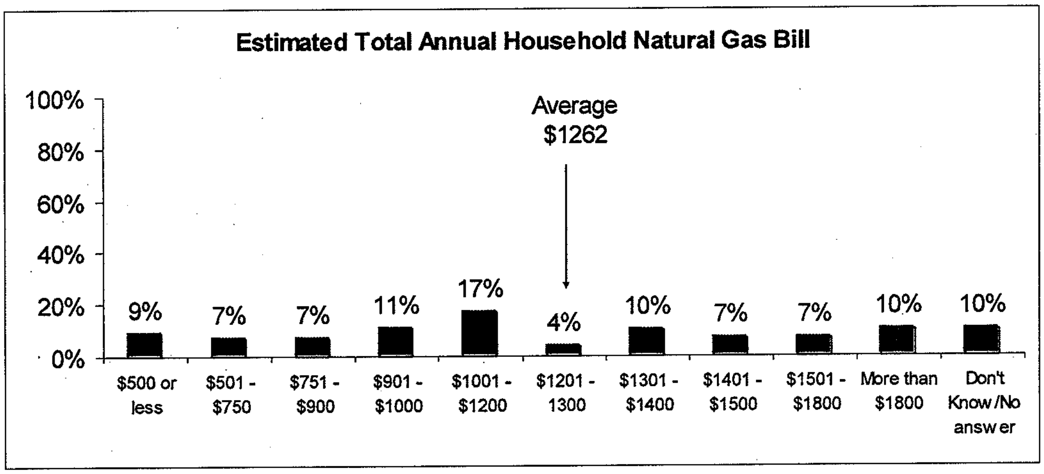
- Those who own their home with no mortgage (30% vs. 17% among those who own their home with a floating rate mortgage).

The following were more likely to prefer Less Hedging:
- Those aged 35 – 44 (26% versus 14% among those aged 45 – 54)
- Natural gas customers for 31+ years (23% versus 13% among customers for 5 years or less)

Estimated Total Annual Household Natural Gas Billings

Next, respondents were asked to estimate their total annual household natural gas billings. The purpose of the question was to help put into context the relative value (%) for how much change in natural gas costs respondents could live with in a given year.

Q9.	Approximately how much is your total annual natural gas bill including all charges and taxes?
***Base*:**	Total Unweighted Sample (n=1000)



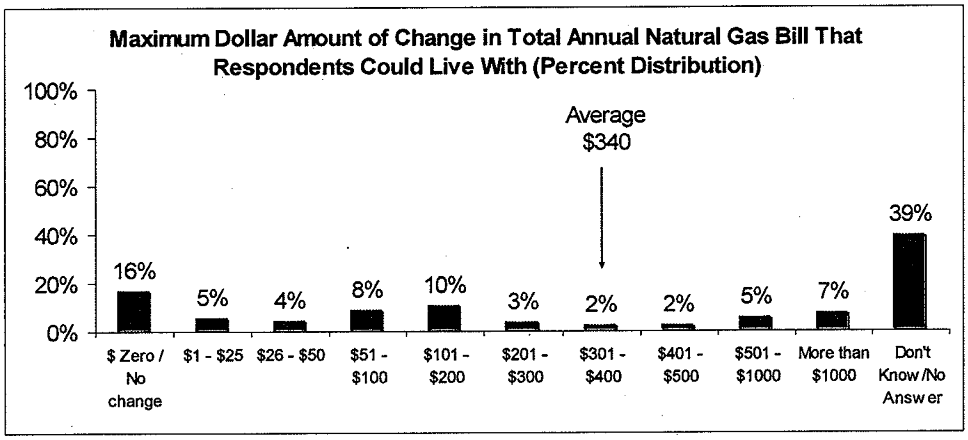
The above chart shows customers' annual natural gas billings which were typically between $500 and $1800, and averaged $1262 per year.

Sub-Group Differences:
- As expected, annual natural gas costs were higher in the Interior ($1281) and Lower Mainland regions ($1299) than for Vancouver Island ($956).
- Those with higher levels of concern about future natural gas price fluctuations (8 or higher out of a possible 10) tended to have higher annual natural gas costs ($1316) than those with lower levels of concern (5 or less out of 10) ($1118)
- Those with higher levels of household income tended to report higher annual natural gas costs (e.g., those with incomes of $100,000 or more reported annual natural gas costs of $1629)

Maximum Annual Change in Natural Gas Billings Respondents Could Live With

Next, respondents were asked to provide the maximum dollar amount of change in their annual natural gas billings that they could live with. The percent distribution of responses is shown below with the overall average amount ($340).

Q10.	Recognizing that market prices for natural gas will continue to fluctuate up and down, what is the maximum dollar amount of change in your family's total annual natural gas bill that you could live with?
***Base*:**	Total Unweighted Sample (n=1000)



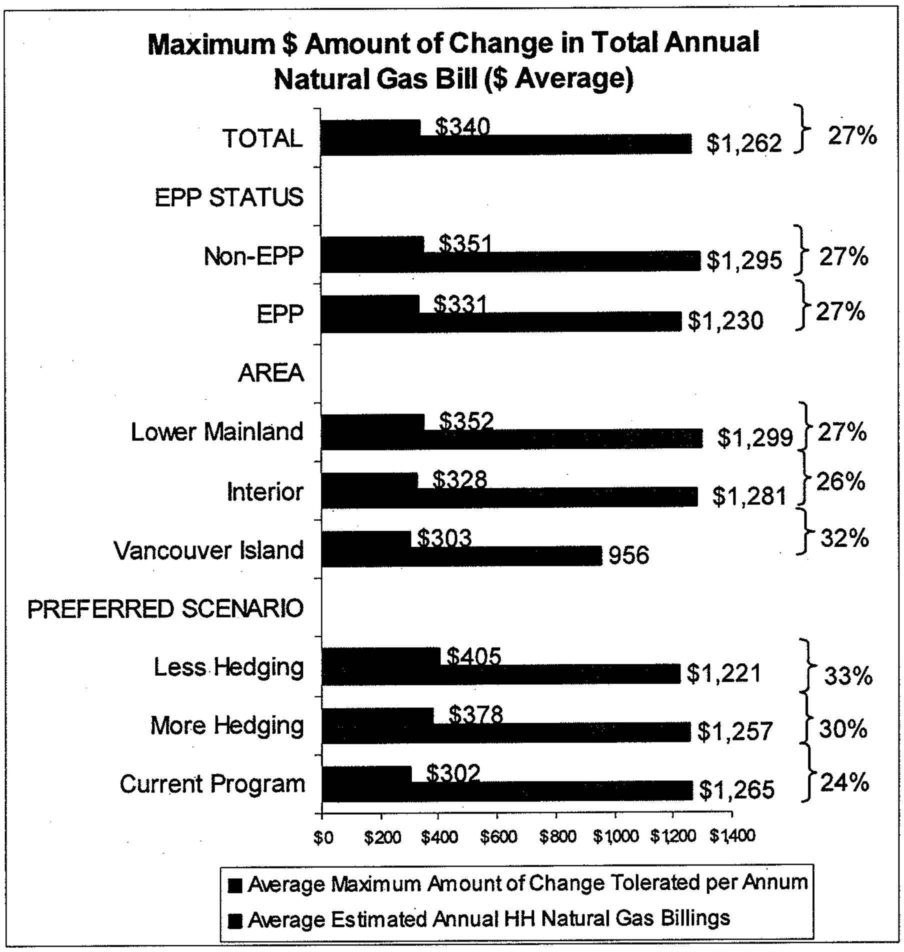
Results show that:

- The minimum amount was $0 (16%), while the maximum was $4000.
- The average amount was $340 (including $0 dollar amounts). Excluding amounts over $1500 the average was $234; and excluding amounts over $1000 the average was $144.
- The median[9] amount of change in annual natural gas billings that customers could live with in a year was $100 for all responses. Excluding amounts over $1500 the median remained unchanged at $100 while excluding amounts over $1000 reduced the median amount to $74.
- The most frequent response categories were $0 (16%), $101-200 (10%) and $51 - $100 (8%).
- Excluding "don't know" responses from the base (not shown in chart), one-quarter of participants providing an answer expressed amounts of $0; just over one-half cited amounts of $100 or less, and 70% said amounts of $240 or less.

[9] the middle value in a distribution, above and below which lie an equal number of values.

The following chart compares respondents' maximum $ amount of change with their (estimated) total annual natural gas billings. Results are shown for the total sample as well as for certain cohorts of interest.

Maximum Average $ Amount of Change in Annual Billings Respondents Could Live With As Compared to their Total Annual Natural Gas Billings



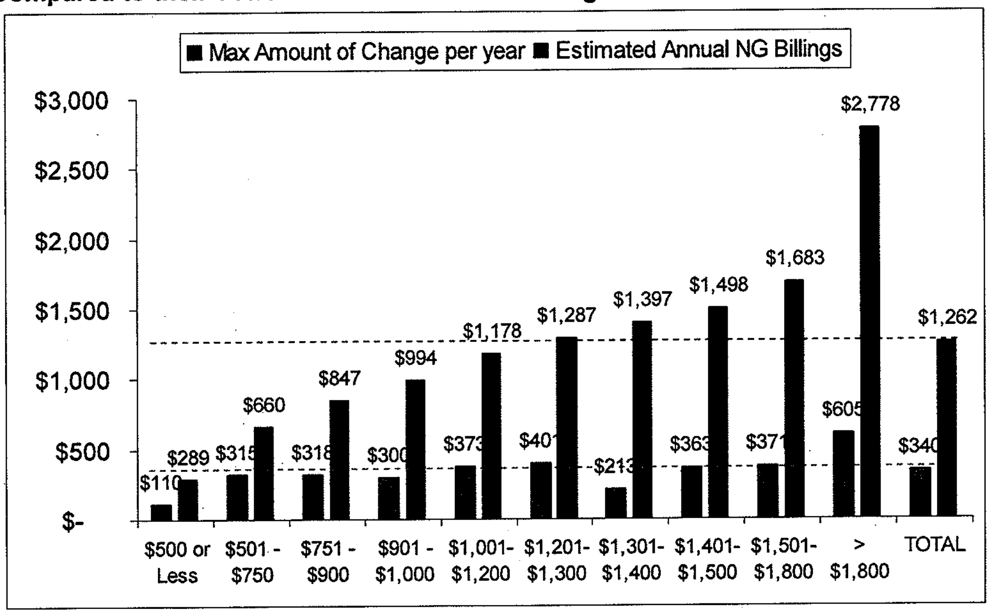
As previously mentioned, respondents' average maximum dollar change in their annual natural gas billings they could live with was $340; this represents 27% of respondents total average estimated natural gas billings ($1262).

Results for key segments of interest are shown in the above chart, but only one statistically significant difference is noted: respondents who preferred the Current Hedging Program gave significantly lower annual average amounts of change that they could live with ($302) than those preferring more hedging ($378) or less hedging ($405). Similarly, as a percentage of total annual estimated natural gas billings, respondents preferring the Current Program also cited lower percentages (24% vs. 30-33%). On the basis of these results, it would appear that respondents preferring the Current Hedging Program are less willing to accept change in natural gas costs than those preferring less hedging or more hedging.

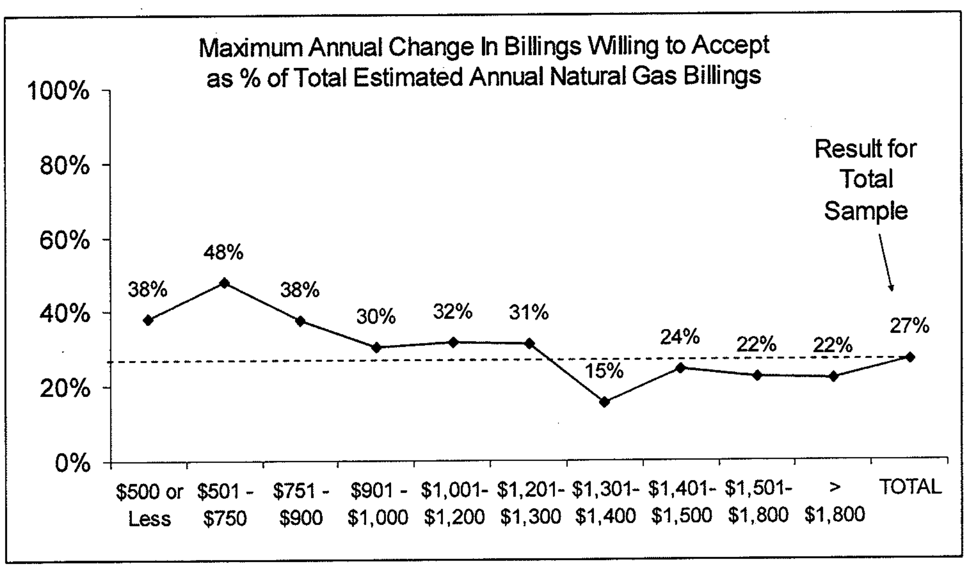
Noteworthy is that there was virtually no difference between customers on the Equal Payment Plan (EPP) versus those not on the EPP. One might have expected those on the EPP to be less tolerant of natural gas price volatility, however, few significant differences were found.

The chart below shows a) the *average annual natural gas billings* for each of eleven dollar amount categories along with b) the *corresponding average maximum annual increase in billings* that respondents in each category could live with (the dotted line shows results for the total sample). The subsequent chart shows b) as a percent of a) for each of the eleven categories.

Maximum Average $ Amount of Change in Annual Billings Respondents Could Live With As Compared to their Total Annual Natural Gas Billings



Maximum Average $ Amount of Change in Annual Billings Respondents Could Live With as a Percentage of their Total Annual Natural Gas Billings



Results show that for the total sample, the maximum amount of increase that respondents could live with averaged 27% of their total annual natural gas billings (see dotted line on lower chart). Comparing this proportion across each of eleven categories, we see that respondents having smaller annual gas billings (e.g. $900 or less) tended to be willing to accept higher proportions (e.g. 38% - 48%) while those with higher annual gas billings (e.g. >$1300) tended to accept somewhat lower proportions (e.g. 15% to 27%). A hypothesis to explain this finding is that those with lower annual natural gas billings may be willing to accept a proportionately higher amount of price volatility because the dollar amount of change at stake is smaller and so may pose less of a potential disruption to household budgets.

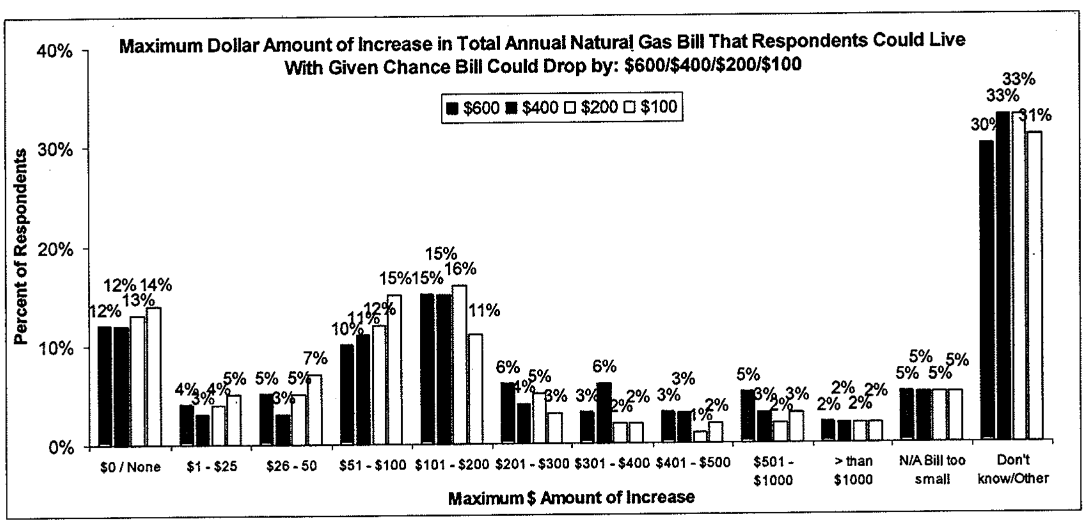
Sub-Group Differences:

- Those who preferred the Current Hedging Program tended to report a lower average maximum amount of change in their annual natural gas bill that they could live with ($302) than those who preferred More Hedging ($378) or Less Hedging ($405).
- Those with annual natural gas expenses of $500 or less gave a lower average amount of fluctuation in natural gas costs that they could live with ($110) than those with annual expenses of $1800 or higher ($605).
- Those with a higher level of concern about future natural gas price fluctuations (defined here as 8 or higher out of a possible 10) tended to report a lower average amount of change that they could live with ($301) than those with a lower level of concern (7 or less) ($393)

Maximum Annual Increase in Natural Gas Billings Given Four Levels of Possible Savings

The following question was asked to determine if different dollar amounts of potential *savings* in annual natural gas billings changed the amount of *increase* in annual billings that respondents could live with.

Q11a-e	If an expert told you that your gas bill could *decrease* by: [a. $600 b. $400 c. $200 d. $100] or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?
***Base*:**	Total Unweighted Sample (n=1000)



Results show that to a large extent, respondents' answers remained constant regardless of the amount of potential decrease in their annual billings. In other words, the distribution of respondents' answers remained the same given four different potential savings scenarios: $600, $400, $200 and $100. For example, 12% of respondents said they would not accept any ($0) increase in their total annual household billings given the chance their billings could drop by $600. This finding is not significantly different than the 14% who said they would not accept any increase in their billings given the chance their billings could drop by $100.

This would indicate that as the potential for savings increases or decreases, respondents are not willing to increase or decrease the maximum amount of increase they are willing to tolerate. Rather, respondents have a maximum tolerance for natural gas price fluctuations which remains constant. Perhaps this is because residential consumers of natural gas do not think in terms of the potential for savings on their natural gas bill, but rather the maximum amount of change they are willing to live with.

4.0 Sample Demographics

The following tables provide details on the demographic composition of the sample of slot machine players interviewed in the survey.

Sample Demographics	Weighted Percent (Unweighted Base n=1000)
Equal Payment Plan	
Household on EPP	50%
Household not on EPP	50%
Gender	
Female	55%
Male	45%
Education	
Less than High School	12%
High School Graduate	25%
Some Post Secondary	17%
Completed college/Technical/Vocational/Trade	15%
University Degree	29%
Refused	2%
Respondent Age Category	
18 – 24	<1%
25 – 34	3%
35 – 44	9%
45 – 54	15%
55 – 64	20%
65 and over	52%
Refused	1%
Own or Rent?	
Rent	3%
Own Home with Fixed Rate Mortgage	18%
Own Home with Floating Rate Mortgage	7%
Own Home No Mortgage	69%
Don't know/Refused	3%
Total Annual Household Income for 2004	
< $20,000	8%
$20,000 to < $40,000	20%
$40,000 to < $60,000	19%
$60,000 to < $80,000	13%
$80,000 to < $100,000	5%
$100,000 or more	10%
Don't know/Refused	27%
Length of Time a Natural Gas Customer in BC	
5 years or less	7%
6 – 10 years	9%
11 – 20 years	15%
21 – 30 years	22%
31+ years	45%

Sample Demographics	**Unweighted Percent (Unweighted Base n=1000)**	**Weighted Percent (Unweighted Base n=1000)**
Region		
Vancouver Island	20%	9%
Interior	28%	27%
Lower Mainland	56%	63%

Appendices

A. Questionnaire

Appendix A: Telephone Survey Questionnaire

NATURAL GAS PRICE VOLATILITY SURVEY – RESIDENTIAL
Draft 7 – February 22, 2005

A. My name is ________. I am calling on behalf of Western Opinion Research a professional market research firm. This evening we are calling to conduct a short survey with natural gas customers in BC. The study is being sponsored by Terasen Gas and will take about 10 minutes.

May I please speak with the person in the household who is responsible or partly responsible for reviewing and paying for the household's natural gas bills?

IF SPEAKING: [CONTINUE]
IF RESPONDENT COMES TO PHONE: [REPEAT INTRODUCTION AT A]
IF RESPONDENT UNAVAILABLE: [ARRANGE CONVENIENT TIME TO CALL BACK]

I can assure you that your answers will be anonymous because they will only be grouped with the responses of others, and no one's identity will be revealed.

S2. Please tell me if you or any members of your immediate family hold jobs with any of the following:

a Any Media including Radio, TV or print media [THANK AND TERMINATE]
b Advertising [THANK AND TERMINATE]
c Market Research [THANK AND TERMINATE]
d Terasen Gas or subsidiary of Terasen Incorporated [THANK AND TERMINATE]
e A Natural Gas Distributor, Producer or Natural Gas Marketer [THANK AND TERMINATE]

IF NECESSARY:

- The purpose of this call is to conduct a survey; we are not selling anything at all.
- IF ASKED HOW WE GOT THEIR NAME: Your name and phone number were randomly selected from a customer list provided by Terasen Gas.
- IF CUSTOMER WANTS TO BE TAKEN OFF LIST FOR FUTURE RESEARCH AND IS A LOWER MAINLAND OR INTERIOR CUSTOMER Please call the Terasen Gas Customer Care Centre at 1-888-224-2710 and tell them you don't want to be contacted by Terasen Gas to participate in market research.
- IF CUSTOMER WANTS TO OPT OUT OF FUTURE STUDIES AND IS A VANCOUVER ISLAND CUSTOMER Please call the Terasen Gas Customer Care Centre at 1-800-667-6064 and tell them you don't want to be contacted by Terasen Gas to participate in market research.
- IF CUSTOMER SAYS THEY HAVE OPTED OUT OF TERASEN GAS STUDIES "Please accept our apologies. The customer list used for this study may have been generated before you advised Terasen Gas that you did not want to participate in any research studies." Then thank and hang up.
- IF CUSTOMER WANTS TO VERIFY THE LEGITIMACY OF THE RESEARCH Please call Terasen Gas at 604-576-7000 and say they you would like to verify the legitimacy of this research that is being conducted by Western Opinion Research.

IF VANCOUVER ISLAND:
S3. To begin, are you on the Terasen Gas Equal Billing Payment Plan? [AS NECESSARY: With the Equal Billing Payment Plan, those who participate in the plan pay the same amount for gas each month, instead of paying higher bills in the winter when gas use increases.]

[IF ASKED HOW IT WORKS: Terasen Gas estimates your gas use for the next year based on your past 12 months of gas consumption, and divides your total charges into 12 equal installments.]

Yes- WATCH QUOTAS!
No WATCH QUOTAS!
DON'T KNOW = NO FOR QUOTA TRACKING PURPOSES
REFUSED – TERMINATE WITH THANKS "Thank you, those are all my questions"

Q1a. Sometimes there are a number of ups or downs in the prices of products and services within a given year. These ups and downs in prices can be called <u>price changes</u> or <u>price fluctuations</u>. For each of the following product or service categories, please tell me how concerned you are about <u>future price fluctuations</u> using a scale from 1 to 10 where 1 is not at all concerned and 10 is extremely concerned. IF NEED TO REPEAT SCALE: please tell me how concerned you are about <u>future price fluctuations</u> for PRODUCT/SERVICE using a scale from 1 to 10 where 1 is not at all concerned and 10 is extremely concerned.

RANDOM
a Electricity
b Telephone
c Gasoline
d Natural Gas
END RANDOM

ASK Q1B RIGHT AFTER D
Q1b .IF 7, 8, 9 OR 10 TO NATURAL GAS IN Q1a Why are you concerned about natural gas price changes or fluctuations?

READ Your gas bill is comprised of the amount paid for the natural gas itself, plus charges for delivering the natural gas to your home, and taxes.

Q2. Terasen Gas buys natural gas on the open market and passes on the cost of this natural gas to its customers at cost, that is, with no markup or added charges? Were you aware of this?
Yes
No
Don't Know [That is, is not aware]
Refused

Q3. What do you think causes the open market price of natural gas to fluctuate up and down?
[DO NOT READ] PROBE FOR CLARIFICATION AND COMPLETENESS OF RESPONSE
RECORD VERBATIM **AND** CODE RESPONSE

Hot or Cold Weather
Natural Gas Production Costs
Costs of Distributing Natural Gas to Households
Profit taking by natural gas producers
OTHER SPECIFY ________________
DON'T KNOW
REFUSED

Q4. Are month-to-month changes in the amount of <u>your</u> household's natural gas bill typically due to changes in the <u>price</u> of natural gas, or due to changes in your household's <u>consumption</u> of natural gas? IF BOTH, SAY Which one, price changes or consumption changes, causes more of a change in your household's natural gas bill.

Changes due to Price
Changes due to Consumption
BOTH PRICE AND CONSUMPTION [ACCEPT BUT DO NOT READ IF THEY CAN'T CHOOSE]
DON'T KNOW
REFUSED

Q5. Are you aware of any measures or programs that Terasen Gas operates or that it may operate on behalf of its customers to manage or "smooth-out" fluctuating natural gas prices? [IF NECESSARY: This does <u>not</u> include the [IF MAINLAND: Equal Payment Plan IF VANCOUVER ISLAND: Equal Billing Payment Plan] where customers, if they choose, can spread their annual energy costs evenly across the twelve months of the year.]

Yes
No
Don't Know [That is, is not aware]
Refused

Q6. [IF YES] What measures are you aware of? [IF NECESSARY: This does <u>not</u> include the [IF MAINLAND: Equal Payment Plan IF VANCOUVER ISLAND: Equal Billing Payment Plan] where customers, if they choose, can spread their annual energy costs evenly across the twelve months of the year.] [DO NOT READ]
RECORD BOTH VERBATIM AND CODED RESPONSE

NATURAL GAS HEDGING PROGRAM
OTHER SPECIFY ________________
DON'T KNOW
REFUSED

HEDGING PROGRAM

READ
Currently, Terasen Gas does operate a hedging program on behalf of its customers to moderate or smooth out price fluctuations of natural gas purchased on the open market.

It works much like different mortgage rate plans such as Variable Rate and Fixed Rate mortgages. Fixed Rate mortgages eliminate interest rate changes, while Variable Rate mortgages can change with the market. Having a fixed rate is better if interest rates go up because you don't pay more than your fixed mortgage rate. Having a variable rate is better if interest rates go down because you can benefit from declining rates.

In a similar way, Terasen Gas' hedging strategy is used to reduce but not completely eliminate market price fluctuations. In other words, the current hedging program has some variable and some fixed pricing.

Q7a Do you support or oppose Terasen Gas' program to hedge natural gas prices? Would that be strongly or just somewhat?

Strongly support
Somewhat support
NEITHER [VOLUNTEERED]
Somewhat oppose
Strongly oppose
DK/Refuse

IF NEITHER, DON'T KNOW OR OPPOSE Q7a ASK
Q7b. Why do you say that? PROBE FOR CLARIFICATION AND COMPLETENESS OF RESPONSE
RECORD VERBATIM RESPONSE

Q8 I am now going to read you three different points of view about Terasen Gas's hedging program to reduce **natural gas** price fluctuations. After I read all three statements, I would like you to tell me which one of the statements is closest to your own view.

Here are the three statements. First, some people say...

[RANDOMIZE ORDER B AND C]

a. Terasen Gas should continue its present hedging program to smooth out natural gas price fluctuations.

Second, some other people say...

b. Terasen Gas should hedge less and not smooth out price fluctuations as much as it does. Instead, it should pass on more of the actual ups and downs of market prices to its customers. This would allow customers to benefit more from any drop in natural gas prices, but they may also have to pay more if market prices increase.

Third, some other people say…

c. Terasen Gas should hedge more to further smooth out natural gas price fluctuations. This would provide a fixed price for natural gas which would protect customers from potential increases in the price of natural gas but on the other hand would not allow them to benefit from potential decreases in price.

Which of these three points of view best represents your view on this matter? The current hedging program; [ROTATE ORDER]: the program with more hedging to even further smooth out price fluctuations; or the program with less hedging which would allow more price fluctuations

Q9 Approximately how much is your total annual natural gas bill including all charges and taxes? An estimate is fine.

INTERVIEWER: READ AVERAGE IF RESPONDENT IS UNABLE TO ESTIMATE THEIR ANNUAL GAS BILL. AS NECESSARY HELP RESPONDENT "DO THE MATH" TO CALCULATE ANNUAL COSTS.
PROGRAMMER: REVEAL APPROPRIATE AVERAGE BASED ON SAMPLE AREA

[IF DK VANCOUVER ISLAND READ: The average annual residential natural gas bill for your area is about $1000. Is yours around this amount or would it be higher or lower? About what might it be? An estimate is fine.]
[IF DK MAINLAND READ: The average annual residential natural gas bill for your area is about $1400 Is yours around this amount or would it be higher or lower? About what might it be? An estimate is fine.]

RECORD ANNUAL DOLLAR AMOUNT OF NATURAL GAS BILL
DON'T KNOW
REFUSED

Q10 Recognizing that market prices for natural gas will continue to fluctuate up and down, what is the maximum dollar amount of change in your family's total annual natural gas bill that you could live with?

RECORD ANNUAL DOLLAR AMOUNT OF CHANGE
DON'T KNOW
REFUSED

For each of the following questions, please tell me how much of an increase in your annual gas bill you could live with, knowing that your bill could decrease by a given amount.

Q11a. First, if an expert told you that your gas bill could decrease by **$600** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live in this case? ADD IF R SAYS DECREASE UNREALISTIC SAY "Assuming this could occur, what is the maximum increase in your annual bill that you could live with?"

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL
DON'T KNOW
REFUSED

Q11b. If an expert told you that your gas bill could decrease by **$400** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL
DON'T KNOW
REFUSED

Q11c. . If an expert told you that your gas bill could decrease by **$200** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL
DON'T KNOW
REFUSED

Q11d . If an expert told you that your gas bill could decrease by **$100** in a year, or that it might increase but they couldn't tell you by how much, what is the maximum increase in your annual bill that you could live with in this case?

RECORD MAXIMUM ANNUAL PRICE INCREASE
NOT APPLICABLE/ANNUAL GAS BILL TOO SMALL –
DON'T KNOW
REFUSED

DEMOGRAPHICS

Finally, I have some questions that will enable us to make sure that we have talked to a good cross-section of households. All responses will be held in strict confidence and will not be attributed to any individual.

Q12. What is the highest level of schooling you have completed?

1. Some high school or less
2. High school graduate
3. Some post secondary (university/college/technical school)
4. Diploma, certificate, or degree from community college, trade, technical or vocational school or business college
5. University degree
6. DON'T KNOW
7. REFUSED

Q13. Which of the following categories contains your age, is it: [READ]

1. 18-24
2. 25-34
3. 35-44
4. 45-54
5. 55-64
6. 65 or older
7. REFUSED

Q14. Which of the following best describes the home you are currently living in? Do you …

1. Rent your home
2. Own your home and have a fixed-rate mortgage
3. Own your home and have a floating-rate mortgage
4. Own your home outright with no mortgage.
5. Other

Q15. For statistical purposes only, we need information about your income. All individual responses will be kept confidential. Which broad income category best describes your total household income before taxes in 2004.

1. Under $20,000
2. $20,000 to under $40,000
3. $40,000 to under $60,000
4. $60,000 to under $80,000
5. $80,000 to under $100,000
6. $100,000 and over

Q16. How long have you been a natural gas customer in BC? AS NECESSARY "The number of years"

RECORD NUMBER OF YEARS_____
DON'T KNOW
REFUSED

18. Record Gender *(Record from voice DO NOT READ)*

1. male
2. female

What are the first three digits of your postal code? _________

18. IMPORT REGION FROM SAMPLE

Thank you for participating in the survey. Thank you very much!

Appendix G

AETHER'S REVIEW OF FEI PRICE RISK MANAGMENT

Price Risk Management Strategies and Tools

FortisBC Energy Inc.

Prepared by Aether Advisors LLC

February 2014

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Executive Summary

FortisBC Energy Inc. (FortisBC) requested Aether Advisors LLC (Aether) assist the Company with an initiative to assess existing and explore new alternatives for managing price exposure for its gas customers. The project scope was to assess options to help manage price risk for customers, focusing on cost, rate stability, and managing uncertainty within the supply portfolio. The range of price risk management options Aether reviewed included rate-setting mechanisms, alternative rate structures and price risk management tools such as storage arrangements, physical fixed price contracts, financial derivatives, and natural gas production. These represent the full range of hedging tools available to gas utilities.

Aether's recommendations for FortisBC's price risk management program are provided in this report. Part I- Setting the Stage, explains why price risk management is critical for providing rate stability for customers. Since the 2011 British Columbia Utilities Commission (BCUC) order suspending the majority of Fortis BC's price risk management program, there have been changes in North American natural gas supply and demand trends that increase the need for price risk management. And, coupled with broader continental gas market dynamics, there are compelling reasons why FortisBC's customers would benefit from more rate stability at current low market price levels.

Customer interests are examined in Part II- Customers' Perspectives on Price Risk Management, underpinning Aether's recommendations that FortisBC re-institute a more comprehensive price risk management program. Rate mechanisms and alternative rate structures can provide price stability for customers, and these are explored in Part III – Rate Mechanic and Alternative Rate Structures. Aether concluded that the current rate mechanisms to provide equal monthly bills and to smooth prices over quarterly periods are important to continue, but that these alone cannot address customer exposure to market price impacts.

While alternative rate structures could be offered to help customers manage price risk, because of administrative and implementation challenges, Aether suggested price risk management within FortisBC's default commodity rate service offering (CCRA) would be a more effective means of meeting customer needs. Part IV – Developing a Price Risk Management Program provides guidelines for a price risk management program, focusing on customer risk tolerance, price risk management objectives, program design, and determining program effectiveness. Part V- Medium-Term Price Risk Management Tools explores the benefits and considerations of several price risk management tools, including storage, physical fixed price contracts, and financial derivatives. Part VI- Medium-Term FortisBC Portfolio Analysis includes illustrative scenario analysis to show how price risk management tools could be used in FortisBC's portfolio, and where hedging guidelines can be developed consistent with a customer risk tolerance.

In Part VII- Long-Term Price Risk Management Tools, Aether reviews several options for locking in prices long-term for customers, including long-term contracts, volumetric production payments and reserves ownership. Aether provides a decision-making framework for exploring long-term price risk management tools, emphasizing the need for fundamental analysis and market price analysis prior to executing long-term hedging in Part VIII – Long-Term Price Risk Management Framework. Additionally, Aether reviews potential future market trends and supplies market price analyses that support long-term price risk management. Current supply and demand factors point to the potential for continued price appreciation. Historical and comparative price analyses illustrate the value of North American gas relative to other energy sources. These are compelling reasons for FortisBC to explore long-term price risk management options in order to lock-in the benefits of low-cost gas for customers for years to come.

Information about other utilities' price risk management programs are included in Part IX- How Other Utilities Look at Price Risk Management. Aether summarized selected utilities' price risk management programs, which could serve as models for a price risk management program for FortisBC. This is not an exhaustive list, but an illustrative list. Information provided about other utilities' price risk management programs is based upon publicly-available information. The descriptions include examples of physical resources, supply arrangements, long term fixed price purchases, derivatives and investment in reserves.

Part X- Conclusions and Recommendations summarizes Aether's findings and suggestions, from the customers' perspective. The recommendations address why price risk management is critically important at this time and urges the utility and its stakeholders to consider potential risk exposures facing customers. Changing supply-demand fundamentals in the North American gas market over the last couple of years have changed the risk profile for FortisBC's customers. From 2009-2012, shale gas production had driven wholesale gas prices lower, and supply exceeded demand. But emerging market factors and government actions appear to be increasing gas demand in the coming years, while the economics for gas production are not particularly attractive at current low prices.

The majority of FortisBC's residential and small commercial customers have little protection from market price volatility under the FortisBC commodity rate. And despite low forward market prices, FortisBC has no hedges in place beyond March 2014. Aether recommends FortisBC consider the following initiatives, several of which echo suggestions made by stakeholders, the BCUC staff and Commission Panel, to help protect customers from medium-term and long-term price and rate increases:

- Understand Customers' Preferences
- Develop a Customer Rate Tolerance
- Re-institute a Medium-Term Price Risk Management Program
- Conduct Scenario Analysis
- Consider Long-Term Price Risk Management Options

FortisBC conducted two customer surveys in 2005 and 2012 and should continue customer research on a regular basis to monitor customer preferences. Based upon those preferences, FortisBC can develop a customer risk tolerance, to guide the price risk management program objectives and design. A customer risk tolerance would define the maximum tolerable amount of rate increase to be passed through to customers. The amount of the risk tolerance will influence the size and scale of the program as well as the program design.

Offering customers alternative rate options looks appealing, but there would be significant challenges in implementation and customer acceptance. Because of the obstacles, Aether recommends FortisBC provide customers price protection through enhancing a medium-term price risk management program, spanning 1-3 years forward in time. The objective would be to protect customers from market price increases and to offer rate stability over the medium-term time horizon.

The Commission decision to stop hedging (except for winter Sumas basis swaps) put customers at risk to rising market prices. For example, although FortisBC customers benefitted from lower gas prices 2011 to 2012, they did not have much price protection when prices increased 2012 to 2013. The problem with stopping the Company's program is that it is time-consuming to re-start, which leaves customers vulnerable to rising prices during the 6-12 months it takes for FortisBC to propose a program, obtain stakeholder support and receive approval from the commission. Therefore, Aether recommends the Company work with stakeholders to design a program with enough flexibility to respond to different kinds of market conditions. For example, Aether proposes the Company and stakeholders consider a program that establishes "book ends" for hedging, to allow the Company to adjust hedging percentages depending upon market conditions. A more flexible program with high and low hedging bands would enable FortisBC to provide a minimum threshold of protection for customers, and enable the Company to adjust hedging percentages for observed market trends.

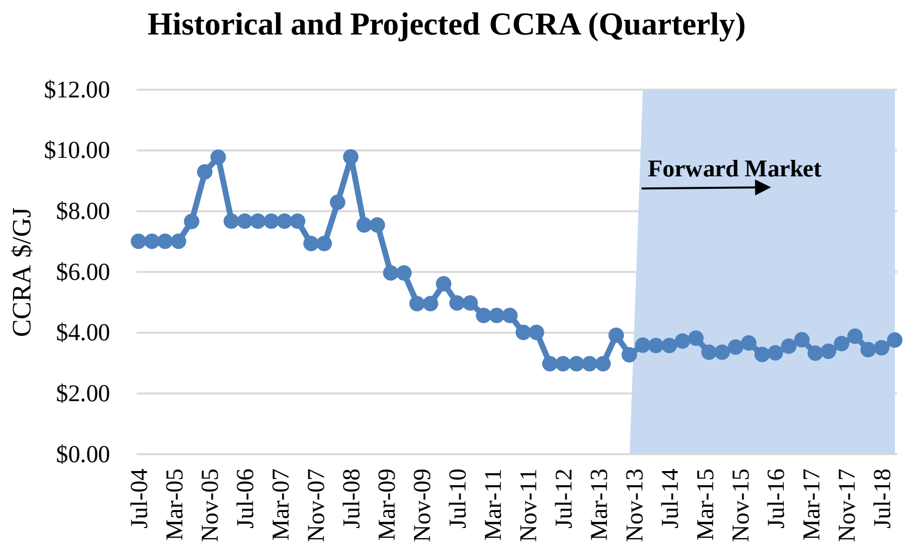
To provide robust analytical support in its medium-term hedging program, Aether suggests FortisBC conduct scenario analysis to understand what types of circumstances and market price moves would expose customers to a rate increase in excess of the customer risk tolerance. Scenario analysis is valuable for testing the impact of different events on a utility's gas supply portfolio to see potential customer rate impact. Robust scenario analysis would allow the Company to test hedging strategies to see their effect on customer rates.

In addition to medium-term hedging, Aether recommends FortisBC explore opportunities for long-term price risk management. Because long-term price risk management requires significant analysis and capital, and the decisions have long-term ramifications for customer rates, Aether suggests the long-term hedging should be pursued with the support of stakeholders and the commission, and only when the right set of conditions exists. Aether proposes long-term price risk management would be appropriate when the forward market offers attractive pricing relative to historical pricing and when the supply and demand factors indicate potential increases in prices from current levels. Aether provides a description of several methods to lock in long-term price protection which include volumetric production payments and reserves.

Using the decision-making framework from Part VII Long-Term Price Risk Management Tools and based upon current supply and demand factors and price analyses, Aether believes there are compelling reasons for FortisBC to consider long-term price risk management. Even though North American production increases are forecasted, gas production economics are not attractive for producers at current gas prices. Further, it is quite possible producers will have to comply with new regulation that could raise their production costs. From a demand perspective, there is new gas demand emerging from economic recovery, retirement of coal plants, North American LNG exports and domestic transportation demand for LNG and CNG.

Perhaps most compelling is that current forward market prices would enable FortisBC to lock in forward prices at historically low price levels. The chart below shows the Company's historical customer commodity rate (CCRA) and a projected commodity rate based upon current forward market prices (using AECO prices as of December 16, 2013):

Figure 1 - FortisBC's Historical CCRA, Projected to July 2018



The above graph is the historical FortisBC monthly CCRA rate through October 2013, and projections into the future based upon forward market prices as of December 13, 2013.

In conclusion, the primary benefits of price risk management are achieving rate stability and insuring supply reliability for customers. The timing is opportune now to evaluate options available to protect customers from potential rate shocks and long-term price increases. Given low current prices, there is significantly less room for market prices to continue to fall, so opportunity costs associated with hedging are less now than they were 2009-2011.

Very few of FortisBC's customers have chosen rate protection through Customer Choice rate offerings, and attrition analysis shows customers have been returning to FortisBC (see Part III-Rate Mechanisms and Alternative Rate Structures for more information). This means that FortisBC is the default commodity supplier to most customers. But at this time, FortisBC has limited capacity to manage price risk for customers outside of seasonal gas storage, basis hedges at Sumas and quarterly rate smoothing mechanisms.

It is important for FortisBC to implement a medium-term risk management program consistent with customers' risk tolerances. Price risk management strategies should reflect customer risk tolerance. Moreover, hedging cost is an important consideration. Price risk management strategies should take into account the trade-offs between what risks were mitigated, the cost to mitigate the risks and the potential opportunity costs associated with mitigating the risks.

Developing a framework to consider all three elements will ensure a price risk management program that meets common objectives of FortisBC, interested parties and the BCUC.

Further, in addition to implementing a medium-term price risk management program, Aether recommends the Company explore options to lock in long-term fixed price protection for customers. At current forward market prices, FortisBC may be able to hedge commodity rates at historically low rates. Given customer demographics, other rising energy costs, and feedback from customer research, this should be very well-received by customers.

The North American and Western Canadian regional supply and demand factors emerging in early 2014 present a different outlook for customers compared to those in summer 2011. Current long-term supply and demand factors and market price analysis indicate the potential for prices to rise from current levels. Given the potential for prices to rise higher from current attractive price levels, FortisBC should explore opportunities to manage medium-term and long-term rate risk for customers.

Price Risk Management Strategies and Tools

Part I – Setting the Stage

The Importance of Price Risk Management

Customers generally are more concerned about rate increases than rate decreases and natural gas delivery is an essential service where customers have limited alternatives, at least in the short-term. Additionally, customers have limited ability to influence energy rates. Therefore customers have an expectation of reliability and relative price stability, in the form of just and reasonable rates. Customers care not only about a short-term rate increase, but also the cumulative rate effect over a period of several years (medium-term time frame). Therefore it is important for utilities to have a price risk management program over a multiple year time horizon. Utilities have to determine how great a rate increase customers can tolerate in a given rate year and over a period of rate years, and then hedge accordingly.

A gas utility has a natural "short" gas position and procures supply to ensure it can reliably meet customers' needs. A utility can minimize the risks of rising natural gas rates for customers through price risk management. When a gas utility locks in a natural gas price to acquire price protection, it is mitigating its short price position. The act of locking in a price is a deliberate action to manage costs.

Price risk management is not speculative for it does not add risk exposure to a commodity portfolio. Instead, price risk management is reducing risk exposure in a portfolio, and is not related to profit and gain or trying to "beat the market". The act of locking into a price means the utility has accepted that price and is willing to forego further opportunity in exchange for protecting against prices moving disadvantageously.

FortisBC has a similar perspective of price risk management. In its prior Price Risk Management Program filing[1], the Company wrote:

"The primary objective of the PRMP (Price Risk Management Plan) has been to:

- Improve the likelihood that natural gas remains competitive with other sources of energy, primarily electricity at this time;

[1] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc., *Price Risk Management Plan Review Report*, January 27, 2011, 2.

- Moderate the volatility of market prices and their effect on rates for customers; and
- Reduce the risk of regional price disconnects."

In recent years, some utility commissions and utility boards have asked, "Why have price risk management programs?" given the downward trend in market prices. Aether advises utilities and regulators that the reasons to manage price risk are:

- To not manage price risks means the utility is speculating with its net short position.
- Customers don't like rate surprises and want to be able to budget for energy costs over time.
- Utilities face rising costs in many areas, so why not manage costs that can be managed?
- There has been a long trend of declining energy prices since 2009 which has begun to turn around in 2012.

Some commissions have ordered utilities to reduce their price risk management programs because of the "cost" of the program was excessive. But in most cases, this determination was made in a vacuum, with minimal consideration for the risk to customers. Reduced hedging has less "cost" in declining markets, but the choice to scale back the hedging is making a bet on the direction of prices. Also, a decision to reduce a program without a quantitative assessment of potential risk exposure to customers, fails to protect customers' interests. Deciding not to hedge when prices are low will not provide much opportunity to customers and instead pose significant risks. Aether recommends decisions around price risk management programs should be driven primarily by the utility customers' risk tolerance, supported by quantitative analysis to determine how much price risk management is appropriate.

Price risk management can be executed in any future time period. But there may be different objectives, depending upon the time frame. In order to provide a context for hedging in a price risk management program, this report addresses short-term, medium-term and long-term price risk management strategies, with greater emphasis on medium-term and long-term:

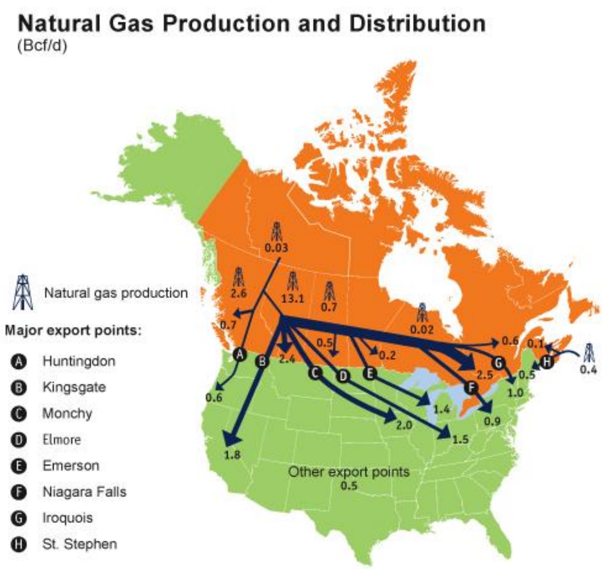
- "Short-Term Price Risk Management" refers to managing commodity cost for the upcoming gas rate year
- "Medium-Term Price Risk Management" refers to managing commodity cost for gas rate years 2-3
- "Long-Term Price Risk Management" refers to the time horizon beyond gas rate year 3

For purposes of this report, price risk management refers to strategies to provide rate stability and to reduce the risk of rising natural gas rates for FortisBC's customers. "Hedging" refers to a subset of price risk management strategies: physical and financial contracts to manage price exposure.

The North American and British Columbia Gas Market

As one of the largest natural gas utilities in western Canada, FortisBC serves 945,000 natural gas customers, operates over 47,000 kilometres of natural gas transmission and distribution pipelines, and meets a peak day customer demand of 1336 TJ of gas. The Company's supply portfolio includes gas supply from British Columbia and Alberta, nexus with numerous pipelines including Westcoast Energy, TransCanada, Foothills, Northwest Pipeline, and storage capacity in British Columbia, Alberta, Washington, and Oregon. FortisBC's system is integrated into a larger North American gas market since the western Canadian gas market interconnects to a variety of Canadian and US markets through pipeline infrastructure to Northeast Canada and US, Pacific Northwest US, Southwest US, and Midwest US. The Centre for Energy map below illustrates the flows of western Canadian gas to other markets[2]:

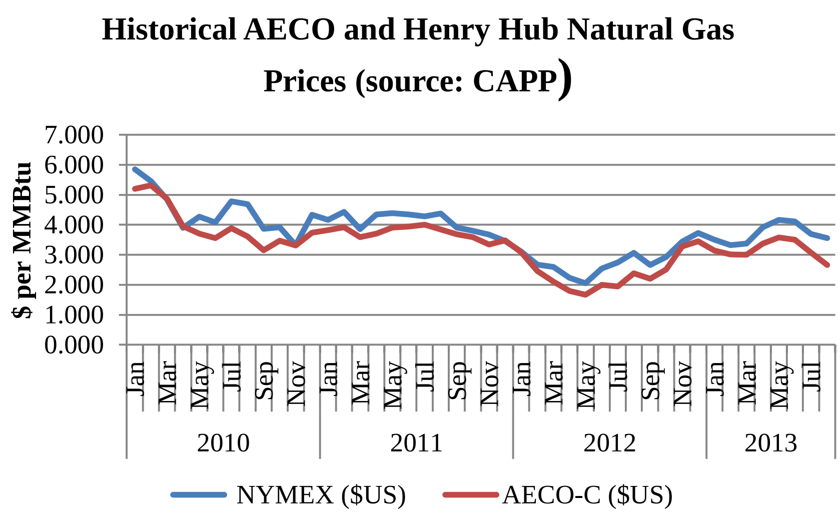
Figure 2 - Flow of Natural Gas from Western Canada to Other Markets



[2] Centre For Energy, *Natural Gas Production and Distribution*, http://www.centreforenergy.com/FactsStats/MapsNorthAmerica/ (accessed December 2013)

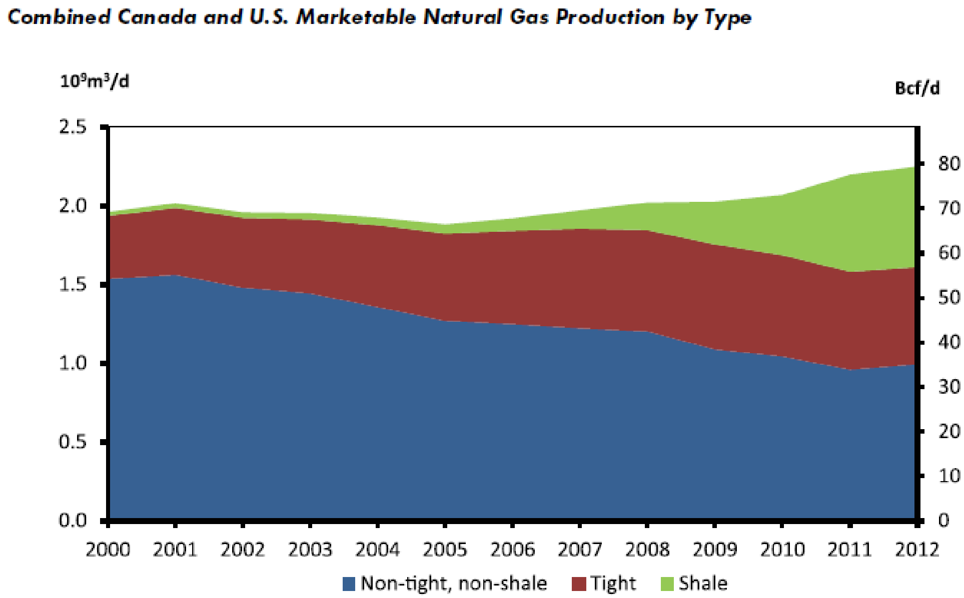
FortisBC's customer rates are impacted by what is occurring across North American gas markets. In recent years, FortisBC's customers benefited from rate decreases as a result of broader North American natural gas fundamentals depressing wholesale natural gas prices. From 2010 to 2012 North American gas market prices (represented by major market hub locations AECO and Henry Hub, LA) dropped. The price chart below illustrates this trend, and the more recent price upswing in price from 2012 to 2013:

Figure 3 - Trends in North American Wholesale Gas Markets



Shale production technology gains led to large production additions, causing North American production to increase in 2008. Production grew at a faster rate than demand, which caused natural gas prices to fall.

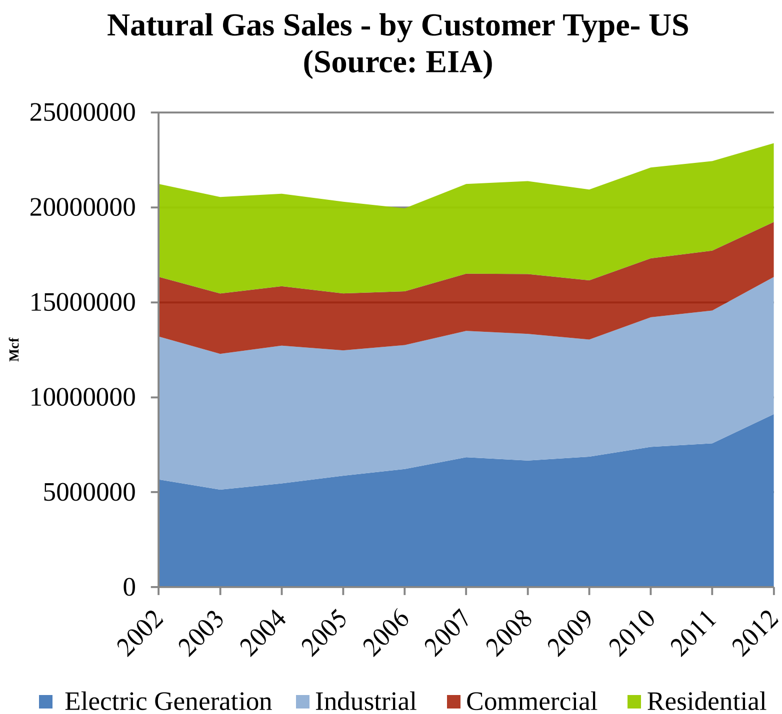
Figure 4 - North American Gas Production [3]



Low gas prices resulting from the production increases have attracted additional demand. While there has been a small reduction in gas demand in the residential and commercial sector, this has been exceeded by demand growth in the industrial and electric generating sectors. After an initial sharp drop in demand in 2009, industrial demand in the US and Canada has recovered to pre-2008 levels. The most significant gas demand increase has been in the US electric generation sector. When natural gas prices fell below coal prices, the cost of generating electricity from natural gas fell below the cost of generating electricity from coal, thus displacing coal generation. [4]

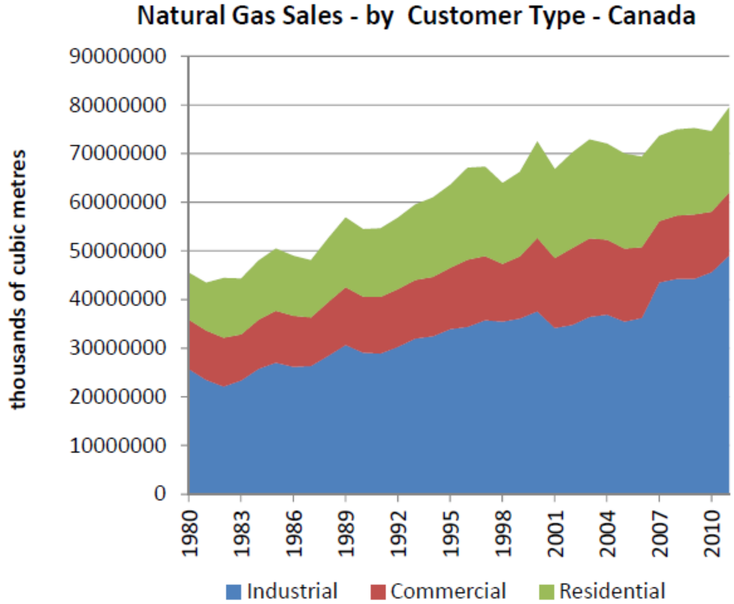
[3] National Energy Board, *Canada's Energy Future 2013, Energy Supply and Demand Projections to 2035,* November 2013, 5.
[4] Future coal plan retirements are addressed in Part VII- Long-Term Price Risk Management Framework.

Figure 5 - US Natural Gas Sales



A similar demand growth pattern in the industrial sector has occurred in the Canadian gas market, coupled with a slightly lower residential and commercial demand:

Figure 6 - Canadian Natural Gas Sales



Source: Statistics Canada #129-0003

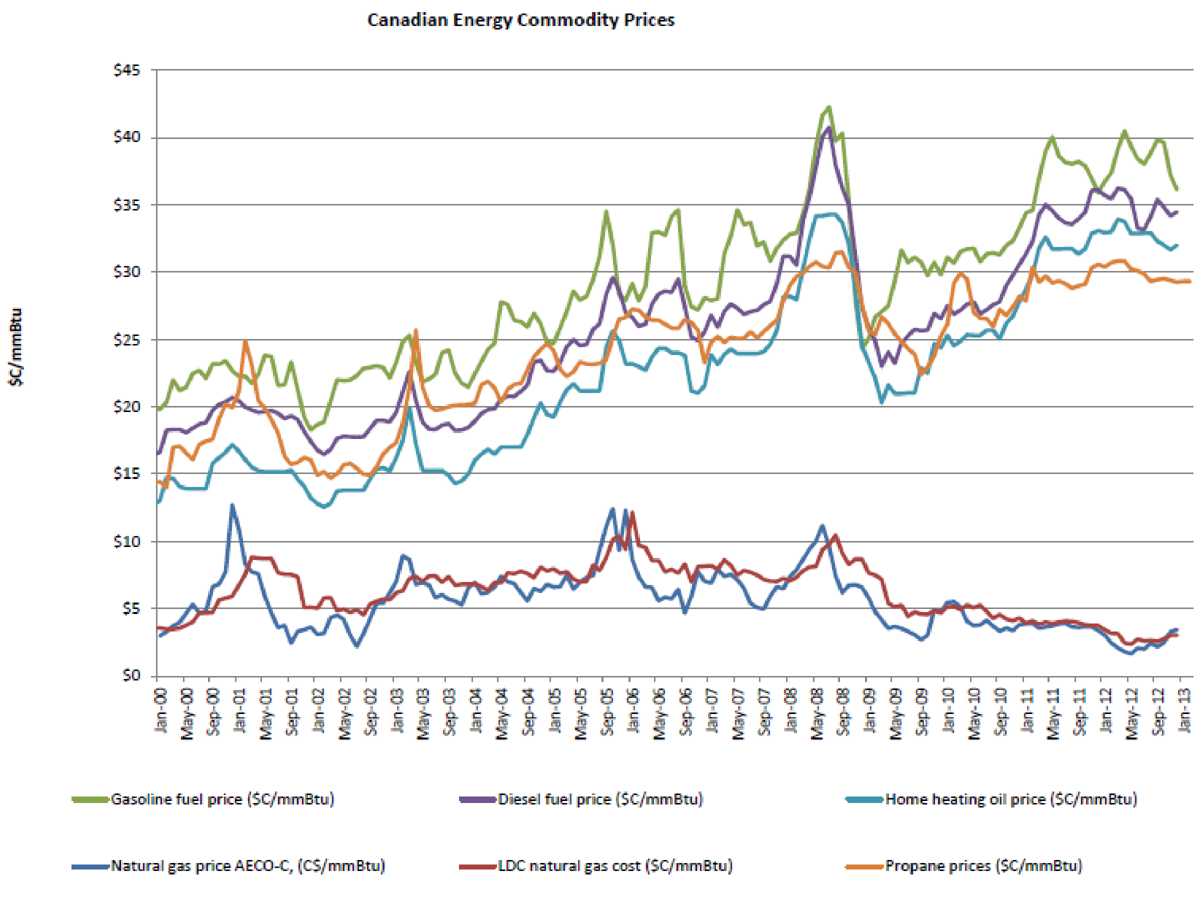
Part VIII – Long-Term Price Risk Management Framework and Appendix B: Long-Term Supply and Demand Analysis provide additional forward-looking fundamental assessment and market price analyses, as examples of long-term price risk management criteria. To summarize, the recent demand trends are expected to continue and more gas production will be needed to meet demand. However, natural gas exploration and production investment returns are not attractive relative to crude oil investment opportunities. Therefore, while shale production from 2009 to 2012 led the way in driving down prices, higher gas prices may be needed in the future to attract new shale gas production. North American natural gas prices are so steeply discounted relative to other energy sources except coal that gas prices could increase significantly before demand destruction occurred.

In addition to changing supply and demand conditions across the broader North American gas market, there are customer-specific issues that may influence customers' perspective on the benefits of price stability. The Canadian Gas Association assembled a number of graphs illustrating the cost of different energy commodities and household spending on energy costs[5].

[5] Gas Stats, Canadian Gas Association, *Canadian Energy Commodity Prices*, http://www.cga.ca/resources/gas-stats/, (accessed: December 2013).

While there has been some price relief in natural gas costs in recent years, Figure 7 shows that other energy costs have been rising. The gasoline and diesel fuel prices are most visible to customers since many are routinely fueling their vehicles. Propane and heating oil costs are relevant as alternative heating fuels for customers.

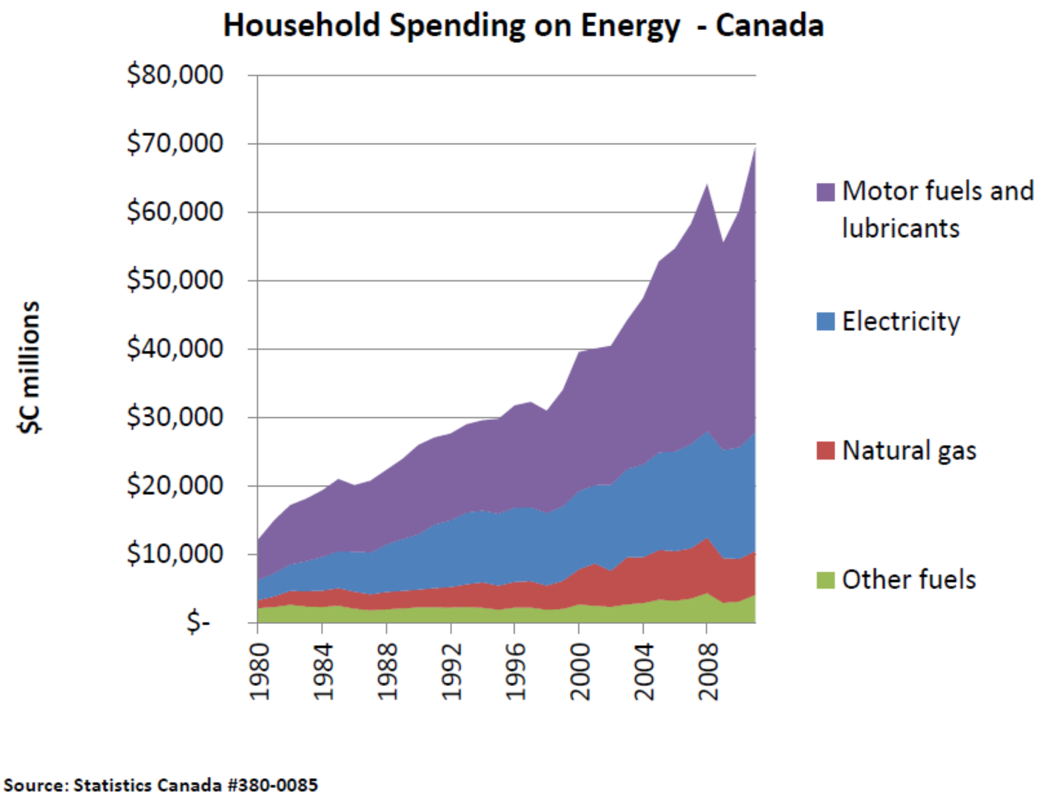
Figure 7 - Canadian Energy Commodity Prices by Fuel Type



Source: CGA, Kent Group, Statistics Canada 326-0009

Figure 8 shows how an increasing amount of household income is directed to energy costs. While natural gas has not risen as much as transportation fuel expenditure and electricity bills, awareness of all energy costs is growing. This may result in customers' increased support for energy cost management.

Figure 8 - Canadian Household Spending on Energy [6]



At the same time that household energy spending is increasing, customer demographics are changing. North America faces an aging population, as the baby boomer generation approaches retirement age and the birth rate has been in decline for some time. In British Columbia, it is estimated that by 2036, the percentage of people over age 65 will grow to 24% from current 2011 levels of 15% and 1976 levels of 10%[7]. This is relevant for utilities because older customers often prefer price certainty, low costs and rate stability.

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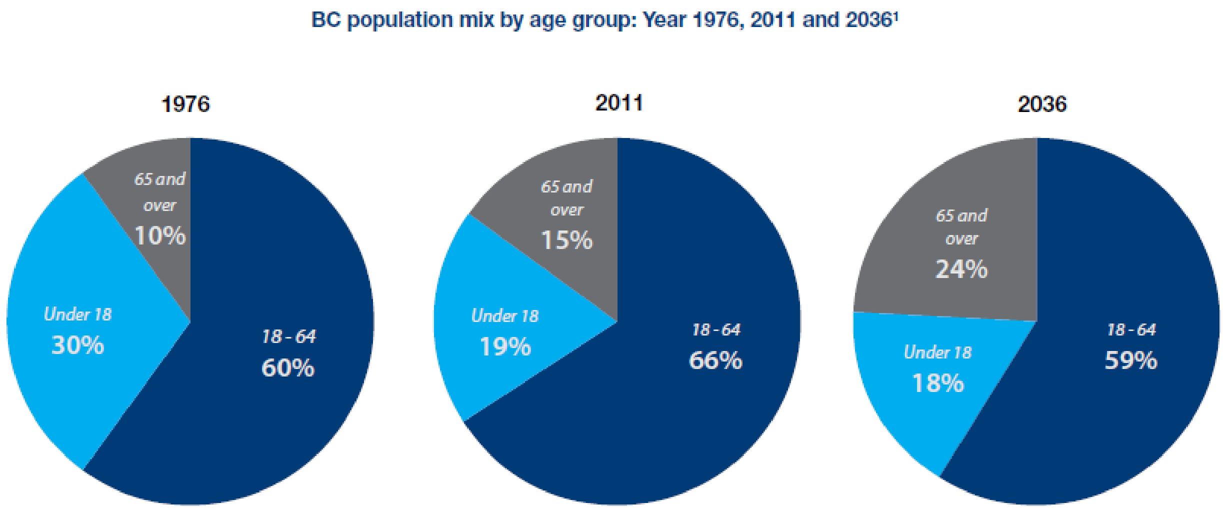
[6] Gas Stats, Canadian Gas Association, *Consumer Spending, Natural Gas and Other Energy, Annual*, http://www.cga.ca/wp-content/uploads/2011/02/Chart-17-Household-Spending-Natural-Gas-and-other-energy.pdf (accessed December 2013)

[7] BCMA Submission to the Select Standing Committee on Health, *Charting the Course: Designing British Columbia's Health Care System For the Next 25 Years*, January 2012, 2.

Figure 9 - Changing Age Demographics in British Columbia



A unique element of British Columbia and FortisBC's service territory is the relative cost of retail electricity. The table below shows that Vancouver BC has the lowest electricity rate for retail customers among major Canadian cities except Winnipeg, Manitoba and Montreal, Quebec as of May 2013[8]. This means natural gas and electricity retail rates are very competitive on a burner tip basis for customers. When customers make an initial capital investment into new natural gas appliances and heating systems, they are expecting natural gas to be competitively priced into the future relative to electricity.

In late November 2013, the British Columbia Energy Minister announced BC Hydro would be increasing rates 9% by April 1, 2014, with another increase of 6% planned by April 1, 2015. [9] Some might argue that projections for rising retail electric rates in British Columbia would alleviate the need to manage gas costs. But gas customers would be unhappy to learn that their gas costs weren't mitigated because provincial electric rates were projected to increase. Gas customers care about the cost of gas that is used in their gas appliances and heating system. In

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[8] Manitoba Hydro, *Electric Utility Rate Comparison*, http://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/utility_rate_comp.shtml (accessed: December 2013).

[9] Dirk Meissner, *BC Hydro Rates To Rise By 25 Per Cent Over 5 Years*, The Canadian Press, re-printed by Huffington Post, Updated: 11/26/2013 6:54 pm EST http://www.huffingtonpost.ca/2013/11/26/bc-hydro-rates-will-jump-_n_4344584.html (accessed: January 2014)

general, customers will assume that electric prices and gas prices are being regulated in a manner to provide just and reasonable costs for each energy source.

Figure 10 - Illustrative Provincial Retail Electricity Rates

Residential Bill Calculations					
One Month Bill For:					
Cities	**375 kWh**	**750 kWh**	**1,000 kWh**	**2,000 kWh**	**5,000 kWh**
Halifax NS	$64.69	$118.55	$154.46	$298.09	$728.98
Saskatoon SK	$61.95	$103.67	$131.49	$242.76	$576.58
Toronto ON	$59.77	$102.52	$131.02	$245.03	$616.11
Calgary AB	$56.80	$ 96.06	$122.23	$226.92	$540.99
Saint John NB	$49.09	$83.03	$105.65	$196.15	$467.65
Vancouver BC	**$32.05**	**$61.92**	**$89.07**	**$197.63**	**$523.34**
Winnipeg MB	$34.03	$60.96	$78.92	$150.75	$366.24
Montreal QC	$32.48	$52.77	$68.66	$146.46	$379.86

At a time when FortisBC's customers may be more aware of energy prices in absolute and comparative terms, and when more of them may be seeking price certainty, FortisBC has little in its portfolio today to manage price risk for customers. Outside of storage which provides a short-term seasonal price protection, FortisBC has no fixed price hedges beyond March 2014 to manage rate volatility for its customers. In Part V – Medium-Term Price Risk Management Tools Aether provides a range of price risk management tools the Company could consider to manage cost volatility and provide rate stability for customers over a medium-term and long-term time horizon.

Part II – Customers' Perspectives on Price Risk Management

In its order G-120-11, the BCUC suggested the Company consider customer interest in alternative rate offerings:

> "Nonetheless, the Panel suggests FEU [FortisBC] consider the CEC proposals among others. First FEU is encouraged to consider the potential of offering an optional Customer Price Stability Fund. As described in Section 4.4, by rate of a rate rider as a percentage of gas commodity purchased, customers would in effect be self-hedging and providing more stability. Second, FEU should consider offering an enhanced hedging program for customers, on an optional basis, along the lines recommended in the filing. After reviewing cost and risk trade-offs, customers can then determine whether insurance in the form of hedging would suit their personal circumstances."[10]

FortisBC has conducted customer research to seek greater understanding of customers' interests and preference regarding management of natural gas price volatility. Most recently, in 2012, FortisBC, together with Sentis Market Research, Inc., conducted a series of customer surveys and focus groups with an objective "to understand customer perceptions of pricing volatility and potential volatility programs."

Seeking customer input on their risk tolerances and options to mitigate risk is not often done by utilities. While the results of this research may, at times, lead to further questions for exploration, it provides a very useful context for consideration of alternate approaches to price risk management. FortisBC's research has provided a number of insights.

Customers indicated in the survey that they are sensitive to natural gas prices. For instance, 44% of residential and 51% of low income customers responded that a 25% increase in bill would be "very likely" to drive changes in behavior. A 50% increase in bill indicated a change in behaviour for 62% of both residential and low income customers. While the research indicated a range of customer sensitivities to rate increases, the higher the potential rate increase, the more uniform the customer' sensitivities became. That is, as the magnitude of rate increases grow (especially beyond 25%) the more uniform the response by customers across all classes. Overall, the customers most sensitive to increases were those who have signed up for FortisBC's Equal Payment Plan (EPP), where FortisBC estimates the customer's gas use for the next year based

[10] British Columbia Public Utilities Commission, *In the Matter of FortisBC Energy Inc. and FortisBC Energy Vancouver Island Inc. 2011-2014 Price Risk Management Plan,* Reasons For Decision, Appendix A, to Order G-120-11, July 12, 2011, 25.

on the past 12 months of gas consumption and divides expected total annual charges into 12 equal monthly bills.

The popularity of FortisBC's EPP provides some indication of customer preferences for stability. While the EPP has limited ability to provide price protection, customer interest in the program was high, with 41% of residential and 40% of low income customers surveyed signed up. For those previously unaware of the program, many indicated that they would sign up now knowing of the program. The very strong interest in the EPP as a tool that addresses customer desires for stability and predictability may indicate a further customer interest in stability beyond what the EPP can provide.

The research indicates that customers were aware of current expanded supply of natural gas and generally expected gas costs to remain stable in the near term. However a majority (64% of residential, 62% of low income and 69% of businesses) were "concerned" or "extremely concerned" about increasing natural gas price risks. This suggests that customers would have an interest in preserving the current benefits of low-cost gas supply and to protect against the future price increases over the long-term.

This research tested customer interest in potential alternatives to manage natural gas volatility. While Sentis concluded customers generally see a role for FortisBC to provide mechanisms to help manage customer bill volatility, customers indicated in focus groups that they prefer a small number of options that are easily understood. The research found that customer confusion over options could be a significant impediment to providing optional programs to help address gas cost volatility.

In this research, customers were presented with an array of alternative rate options. 41% of residential customers indicated interest in the Pay the Market, 17% in the Price Protect (fixed price) option, 10% in the Rate Cap option, 11% in Rate Protect and 19% responded they didn't know which option they preferred. Given customer confusion over relatively simple items such as FortisBC's gas utility bill and the pass-through of natural gas commodity costs, Sentis recommended that if FortisBC were to offer alternative rate options, they should keep the options relatively simple in design and few in number. Other findings included:

- In general, customers are sensitive to potential natural gas price increases and tend to prefer predictability.
- The Customer Choice Program is not popular with many customers due to past Gas Marketer sales techniques and concerns over being locked into complicated contracts, especially if prices were to decline.

- While more customer education would be useful in determining preferences among the specific options, customers tend to prefer options that would allow them to capture the benefits of low gas prices but protect them if gas prices rise.
- Customers prefer fewer options (one or two) that are transparent and understandable.
- Customer understanding of issues such as bill structure, value provided to customers by Fortis in managing risk, and the nature of gas supply markets, is important for success in developing price risk management options for customers.
- Customer trust and confidence in risk management programs is essential.
- Successful risk management approaches will benefit from continued customer education and engagement.

FortisBC's customer research provides a good foundation upon which to consider price risk management options. Continued customer engagement would help FortisBC continue to refine its price risk management program. One of the gaps in the 2012 survey is that customers were not provided different prices for different programs, and only responded to a qualitative explanation of the program design. Gathering further customer intelligence could assist FortisBC in understanding how different risk management tools address underlying customer needs and interests, as well as understand the trade-offs customers would make between program cost and risk. Customer research could also help FortisBC launch new programs more effectively.

A number of approaches can be taken to engage customers, to investigate more fully their interest in and receptivity to alternative risk management approaches and tools and to ensure program success. These include quantitative research, focus group research and customer advisory panel.

A. Quantitative Research

Building upon the online surveys conducted in 2012, further investigation of customer preferences regarding risk management efforts can be conducted using conjoint analysis. Typically, customer survey techniques ask customers to rate the importance of various attributes or interests. Such surveys are often quite useful in determining which product or service attributes are valuable and which are not. However, they typically are less useful when attributes must compete against each other. Often this is the case and individuals must make choices among competing interests. Conjoint analysis is the most commonly used approach among market researchers to statistically determine how respondents implicitly rank various attributes as they make complex choices.

Conjoint analysis begins with participants making a series of tradeoffs among a range of alternatives. Each alternative is comprised of a different weighting of attributes. The participants must then rank the alternatives. Quantitative analysis of the participant choices reveals the importance implicitly assigned to each attribute. Participants are provided a number of alternatives from which to select. Each alternative would be ranked, allowing the participant to prioritize among the alternatives. Through this forced ranking, participants are implicitly making tradeoffs among attributes. Quantitative analysis of the results then presents the relative importance of each attribute. The results can prove essential in making design, investment and market development decisions.

Using conjoint analysis for a price risk management program survey, the market research firm would encourage customers to make trade-off decisions and prioritize their preferences. For example, one conjoint analysis could frame the tradeoffs between fixing price and having opportunity to participate in lower markets. Another conjoint analysis could compare and contrast different strike prices and premiums to see customers' preferences. The survey respondents are asked to rank trade-offs:

> Example: Trade-offs with fixed price hedging (Rank the options 1 -5, with "1" being most desirable and 5 being less desirable):

- In rising wholesale markets, customer commodity rates would go up 15% of the total market move up. In falling markets, rates would decline only 15% of the overall market decline.
- In rising wholesale markets, customer commodity rates would go up 25% of the total market move up. In falling markets, rates would decline only 25% of the overall market decline.
- In rising wholesale markets, customer commodity rates would go up 50% of the total market move up. In falling markets, rates would decline 50% of the overall market decline.
- In rising wholesale markets, customer commodity rates would go up 75% of the total market move up. In falling markets, rates would decline 75% of the overall market decline.
- In rising wholesale markets, customer commodity rates would go up 85% of the total market move up. In falling markets, customer rates would decline only 85% of the overall market decline.

Conjoint analysis is usually conducted in connection with focus group meetings so that an explanation can be provided to customers prior to their ranking of the choices. In addition, conjoint analysis results can typically provide a basis for customer segmentation. Through examination of the variation among customer preferences, natural groupings can occur. That is, a certain clustering of results can emerge where groups of customers value tradeoffs among attributes in similar ways. Descriptors representing each segment can be created that reflect their primary interests (e.g., “risk takers”, “savers”, and “skeptics”). This provides a tangible data for each customer segment that can be used to create service offerings and outreach.

Many risk management approaches involve tradeoffs among competing interests. For instance, some tools incur up-front costs to customers and provide value over time in terms of price protection and risk mitigation. Other tools provide greater protection, but afford little opportunity. Employing ranking and prioritization research methods can reveal the relative value of various attributes among competing interests.

B. Focus Groups

The focus group forum provides an excellent complement to quantitative research. As shown in FortisBC’s 2012 survey, focus groups can reveal many considerations, issues and perceptions not easily captured by surveys. They can provide qualitative considerations regarding underlying beliefs, attitudes and concerns. Incorporating this feedback can be very useful in considering alternative risk management tools, conducting customer education and providing outreach regarding selected strategies with customers and stakeholders.

Typically, marketers use focus groups to develop feedback regarding potential new products. The open discussion format provides an opportunity to explore in more detail issues most important to the participants. In so doing, threshold issues that may present unanticipated obstacles to success can be anticipated and addressed.
Focus groups can also be used to investigate differences in customer interests and values across customer segments and demographics. For example, conducting separate focus groups differentiated by factors such as low-income, location (e.g., rural vs. urban), owner vs. renter, age, and others, may provide further insights into customer risk tolerances and receptivity to approaches to manage price risks. Small business customers can be similarly segmented by industry or organizational type (e.g., schools, hospitals, commercial office, small business, government).

C. Customer Advisory Panel

An expansion of the focus group approach may be useful in providing ongoing feedback regarding risk management tools and strategies. As reflected in FortisBC’s 2012 customer research, energy issues can be complex and difficult for customers to understand in a single session. And subject matter understanding can be a significant obstacle to attaining useful customer feedback. One method to address this issue and increase the usefulness of customer feedback is to establish a customer advisory panel.

Using this approach, a set of customers would commit to a series of sessions over a multi-month period. Early sessions are typically used to educate customers on the issues of interest to the utility. It is often best to include presenters from both the utility and outside groups to provide a range of views and to maximize the credibility of the process. Once customers have built a sufficient knowledge base, they are in a strong position to provide useful feedback regarding the issues of interest.

Once established, such panels can serve as ongoing “sounding boards” for future consideration of issues and opportunities. In utilizing the panels it is important for the utility to have a reciprocal arrangement with the participants that the utility will consider and respond fully to the panel’s recommendations. The utility need not agree with all recommendations but should recognize and formally address the input received. Customers engaging in such a process can feel empowered and appreciated and therefore willing to serve as advocates for resulting actions by the utility.

Such a feedback mechanism that develops an educated and committed group of customers can both complement traditional customer research and provide increased credibility to actions taken that reflect consideration of the process and viewpoints expressed. Finally, these groups can provide useful insights into approaches to reach out to customers regarding initiatives and services.

Part III – Rate Mechanisms and Alterative Rate Structures

Rate Mechanisms

Utilities use a number of rate and regulatory mechanisms to provide customers with short-term rate stability and billing certainty. By spreading out the timing of natural gas cost recovery, customers can be provided near-term predictability that helps them in budgeting, planning and managing month-to-month cash flows. One tool is to convert annual costs into an average monthly bill ("levelized" billing) and another is to recover differences between actual costs and billed costs from customers in a subsequent time period through a deferral account. Levelized billing and a deferral account reduce the immediate impact to customers of increasing gas costs by deferring the adjustment between the actual costs and current rates to a later period. These mechanisms do not eliminate customers' exposure to rising commodity costs, but instead allow the utility to delay passing through the rate increase. Only through a price risk management program or alternative rate offering can FortisBC reduce the likelihood of raising rates as a result of increasing natural gas costs.

A. Levelized Billing

Utilities throughout North America provide levelized bill options to customers. These are designed so that the customer pays an equal amount over a defined time period (typically a calendar year). The payments are typically based on the previous year's usage and include any "true-ups" (i.e., over- or under-collections from the past year).

One example of a levelized billing plan is FortisBC's Equal Payment Plan (EPP). The EPP mechanism reviews a customer's historical usage and divides the annual total into twelve installment payments. Under FortisBC's plan, EPP installments are reviewed quarterly and adjusted if underlying rates change significantly.

FortisBC's 2012 customer research indicates that customers appreciate the yearly stability provided by this tool, particularly in how it averages otherwise large differences between summer and winter bills. The customer survey research conducted in 2012 showed a clear preference by customers (61% of residential and 59% of business) for the EPP quarterly adjustments. If gas costs move significantly during the year, customers tend to prefer that the EPP rate be adjusted in a manner contemporaneous with those changes, rather than seeing a larger change in the EPP rate during the next calendar year.

If FortisBC's commodity costs escalate during the year, the EPP rate can be adjusted to recover these costs in the next quarter. As a result, the EPP mechanism provides a degree of "smoothing" near-term price increases or declines, spreading short-term spikes into the next quarter. However, the usefulness of the EPP in smoothing rates decreases significantly if price increases persist. The EPP does not manage the level of gas costs ultimately paid by customers; it only determines the timing of when those costs are paid.

B. Deferral Account Mechanisms

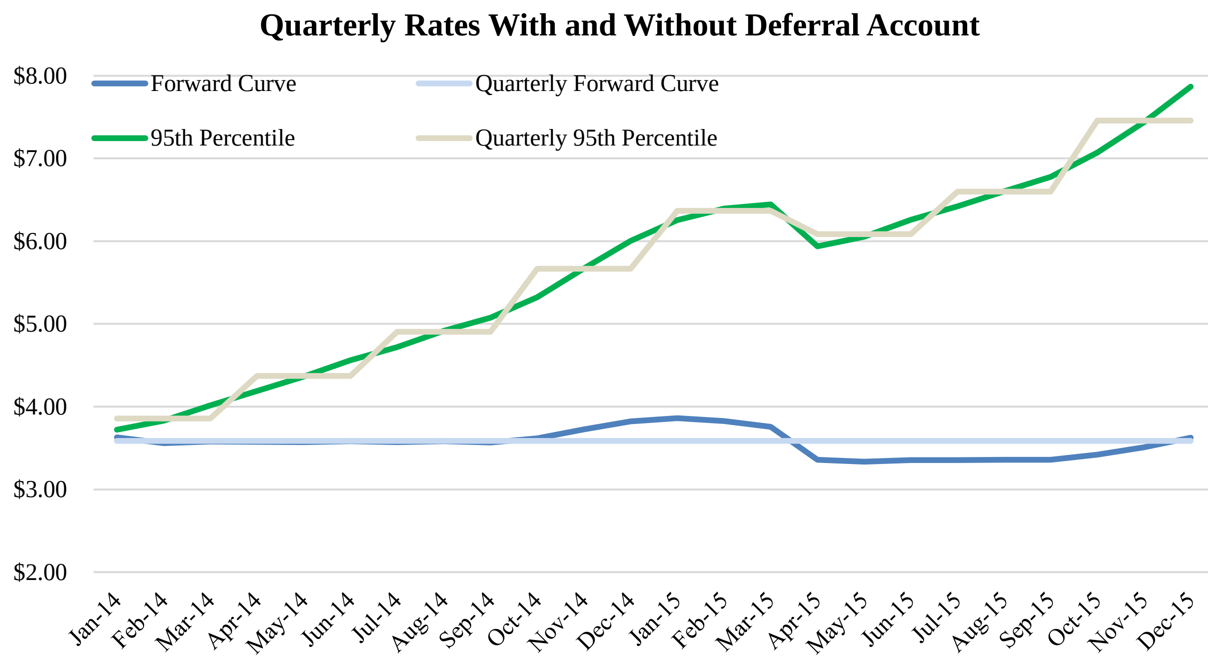
Utilities and their regulators often implement accounting mechanisms that allow costs expended in one period to be recovered in a later period. Gas utilities typically recover all gas supply costs prudently incurred through their commodity rate, and track differences between their commodity rate and actual gas costs in a deferral account. In many jurisdictions these are referred to as Purchased Gas Adjustment (PGA) mechanisms. For FortisBC, the commodity deferral cost mechanism is called the Commodity Cost Reconciliation Account (CCRA).

The use of deferral accounts provides utilities and their investors a degree of comfort that potentially uncertain commodity costs will be recovered. However, an accumulation of large deferral balances can create credit and liquidity concerns. For instance, credit rating agencies tend to view large deferral balances negatively out of concern that subsequent recovery may not fully occur.

Utilities and their regulators employ a range of practices regarding how frequently these rates are adjusted to reflect accumulated deferral balances and forward-looking gas cost forecasts. The longer the time period between adjustments, the greater the near-term rate stabilization potential. However, by waiting longer to adjust rates, a utility only defers rate increases in circumstances where prices rise throughout the ensuing months. In that sense, long-term deferral of costs can produce an illusion of stability when large increases follow, potentially surprising customers.

FortisBC reviews its CCRA rate on a quarterly basis if the amount exceeds a 95% to 105% percent under/over recovery dead band or a plus or minus $.50 per gigajoule dead band. That is, if forecasted twelve month costs are calculated to be outside the dead band, the CCRA rate is adjusted. This mechanism provides a degree of rate stabilization for customers (when considering it against the alternative of monthly CCRA adjustments). However it doesn't protect customers against rising rates if wholesale natural gas prices rise. The graph below illustrates the smoothing effect of quarterly rates, but also demonstrates that customer rates trend upward with wholesale prices if there is no price risk management action taken.

Figure 11 - Deferral Account in a Rising Market



The blue line represents the current forward market price with the price translated into quarterly increments in gray. The green line represents a more extreme market price (using a 95% percentile increase in price), which shows the quarterly CCRA rate rising with market prices. The high gas price scenario came from a price distribution developed with volume weighted forward market prices and forward month implied volatilities as of December 16, 2013.

As noted by the BCUC in its Order G-120-11, the use of these mechanisms described above has limited ability to ensure price stability: "In supporting the continued use of these tools the Panel acknowledges that while deferral accounts provide some smoothing, they do not affect or help manage the underlying commodity prices."[11] In this way, rate mechanisms can provide a useful complement to, but are not a substitute for, tools that address the stability of wholesale gas commodity costs actually incurred by the utility.

[11] Terasen Gas Inc., *In the Matter of the Application by Terasen Gas Inc. and Terasen Gas for Approval of the Price Risk Management Plan Effective April 2011-October 2014*, Order Number G-120-11, July 12, 2011, 24.

Alternative Rate Structures

Following the 2011 BCUC decision, FortisBC explored several alternative rate structures: Customer Price Stability Fund, Fixed Rate Offering and Capped Rate Offering. These structures merit review because they could potentially provide customers with more rate certainty. However, as Aether assessed issues associated with developing such rate structures and considered customer feedback from the 2012 survey, it identified challenges with implementation and customer acceptance.

A. Customer Price Stability Fund

This mechanism would create a separate account, funded through customer rates, to be used to offset costs incurred by the utility beyond what was collected in rates. A surcharge or other billing mechanism would be added to customer rates to build up a reserve account. Then, if gas commodity costs exceeded what the utility was collecting in rates, the utility could use the reserve to recover the incremental costs.

Similar mechanisms have been used by several public power utilities in the Pacific Northwest and in California to address net wholesale revenue and general operating expenses. Rating agencies look favorably upon the mechanisms because the creation of a "rainy day fund" increases certainty the utility will be able to recover its costs.

But, creation of such a fund for managing commodity price risk for FortisBC raises a number of considerations relating to mechanics, efficacy in mitigating risk exposure, and customer support:

- What should the size of the fund be?
- How quickly should it be funded and what rate surcharge would customers accept?
- What type of wholesale market events should it address and when should it be used?
- Does this provide price risk management protection against rising rates?
- Will customers understand the mechanism?

The mechanics would need to be considered carefully. As a first step, determining the size of the fund would be challenging. The utility would have to estimate the size, duration and frequency of the market price movements against which the fund would be applied. Second, the utility and Commission would need to determine how quickly the account should be funded. In an environment of rising energy costs, the utility would want to fund it relatively quickly, but that might require a large surcharge over a short period of time. Third, with respect to using the funds, given that such price changes are very unpredictable, both ex-ante design of the fund utilization and ex-post evaluation of the fund drawdown could be complex. The utility would be challenged to predict when it was appropriate to use account funds unless this was automated.

The bigger question is whether this mechanism would protect customers from rising costs. As with the levelized billing and the deferral account, the Customer Price Stability Fund would act as a buffer between more volatile wholesale markets and retail rates. But it would not actually fix costs or mitigate risk exposure.

FortisBC's 2012 customer research sheds some light on the question of customer interest in such a program. In this research customers were presented with a number of an array of alternative rate options. These options were: Pay the Market Rate, Price Protect, Rate Cap, and Rate Protect. Of all the options presented, Rate Protect (where a customer pays into a stability fund) was less appealing to the customers in the survey. Concerns raised over this program included many associated with "Fortis BC becoming a banker," including issues associated with oversight, how the funds might be used, complexity of the program and how refunds might be addressed. Considering the design and administrative complexities with this program, the lack of customer interest and outstanding questions regarding its design and cost-effectiveness, other tools that effectively help ensure commodity price stability may be more beneficial means to provide customer rate stability.

B. Fixed Rate and Cap Rate Offerings

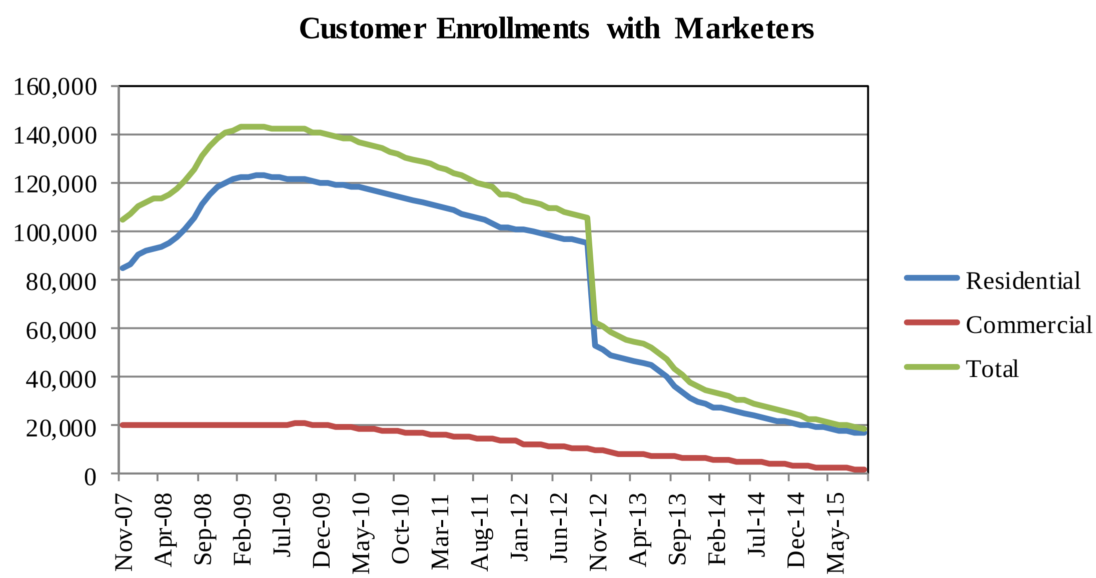
Another potential tool to help protect customers against wholesale price movements is the provision of price rate options. The BCUC noted in its Order G-120-11, "…the Commission Panel believes that it is of the utmost importance to provide customers a choice when it comes to rate stability and the price they are willing to pay for it."[12] Through introducing choice, customers can obtain the gas supply pricing option that best matches their individual risk tolerance. FortisBC's 2005 customer research indicated that surveyed customers had a range in risk tolerance. Therefore, several options in rate offerings would conceivably allow customers to make their own choices between cost and risk.

While marketers serve this role today to FortisBC's customers, there has been customer migration away from marketers and back to FortisBC since 2009 as seen in Figure 12. Results

[12] Ibid., 25.

from the 2012 customer focus group survey FortisBC conducted indicate that some customers distrust third-party marketers.

Figure 12 - FortisBC's Customer Enrollment in Customer Choice Programs



Because most customers have migrated back to FortisBC default service, and since FortisBC does not have a more fulsome price risk management program, FortisBC's customers currently have little gas price protection beyond the short-term. Given the potential for prices to rise in the future, the question is whether it would be more effective for FortisBC to begin to incorporate more price risk management tools into its default portfolio or to offer price rate options for customers to select. The concept of offering customers rate options is very compelling, but the realities make it difficult to implement.

As a starting point for considering what rate options to offer, FortisBC queried customers about four pricing structures - Pay the Market Rate, Price Protect, Rate Cap, and Rate Protect. Customers were most interested in Pay the Market Rate, followed by Price Protect and Rate Cap. It is important to note the survey only described the programs conceptually and did not provide cost projections for customers.

Judging from survey responses, customers have limited understanding of their energy bills, how FortisBC is regulated, and the dynamics of energy market pricing. FortisBC has become the de-facto supplier for most residential and commercial customers, and most customers will not be knowledgeable about future natural gas market factors. This is an important consideration when weighing options to provide stable and low cost energy bills to customers.

The utility could offer Price Protect and Rate Cap options on a forward 1- 5 year basis, similar to the fixed rate offerings provided by third party marketers. Customers could choose such options or remain on "default" service where the customer pays commodity rates as incurred by the utility under its current un-hedged practice. This approach should be considered when customers do not have adequate third party rate options. For example, in its 2008 decision to allow Centra Gas Manitoba Inc. ("Centra", a wholly-owned subsidiary of Manitoba Hydro) to provide fixed-price offerings, the Manitoba PUB found[13] that competition among marketers was weak and determined that Centra's gradual entry into the market for fixed-priced offerings could increase competition to the benefit of customers.

A somewhat similar situation appears to have developed in FortisBC's service territory. There are a very small number of third party marketers offering services to FortisBC's customers. There is only one marketer offering a 1-year option, one offering a 2-year option, two offering a 3-year option, three offering a 4-year option and four offering a 5-year option. [14] The longer-term products are more attractive to marketers because of the larger margin and reduced administrative cost of repeatedly signing up customers for one-year products. But based upon feedback from the 2012 customer focus groups, customers typically are wary of longer-term commitments with marketers.

A comparison of FortisBC's commodity rate (CCRA) and the small number of third party marketers' rates, indicate marketers are offering gas supply at considerably higher prices than FortisBC's residential default rate. The last rate change FortisBC posted was January 1, 2014 for a price of $3.272 CD/ gigajoule. As of January 28, 2014, the third party marketers' rate offerings were materially more expensive:

[13] Manitoba Public Utilities Board, *In the Matter of Centra Gas Manitoba Inc. Fixed-Rate Primary Gas Services Application*, Order No. 156/08, 2-5.
[14] FortisBC, *Retail Choice, Price Comparison,* website url: http://www.fortisbc.com/NaturalGas/Homes/CustomerChoice/ComparingHowRatesAreSet/PriceComparison/Pages/default.aspx (accessed: January 2014)

Figure 13 - Summary of Third-Party Marketers' Rate Offers [15]

Number of Marketers	Term	Residential Fixed Rates per GJ[16]
1	1-Year	$4.89- 6.14
1	2-Year	$5.39- 6.39
2	3-Year	$4.69- 6.39
3	4-Year	$5.60- 7.49
4	5-Year	$4.99- 7.49

The difference between marketers' multiple year contracts and FortisBC's current rate can be explained in part by a small escalation in forward market prices. But most likely, the main difference in pricing is due to marketers including administrative costs and profit margins in their offerings. In contrast, FortisBC passes through commodity costs at procurement cost with no price mark-up[17].

There are policy issues to weigh if FortisBC were to offer customer rate options. When a utility is allowed to compete directly against marketers, marketers may assert that the utility has an unfair advantage through its existing customer relationship (via billing, conservation programs, etc.), cost allocation methodologies, or the "pass through" of gas costs without profit. Addressing such concerns would be critical in planning and obtaining approval for any such programs.

There are operational and cost considerations with offering price protection through alternative rate structures. First, there is less efficiency with the utility hedging small volumes as customers opt-in one at a time, as opposed to hedging within one large portfolio. There is more administrative work to managing smaller rate option portfolios as opposed to managing one large portfolio. Fortis would need to estimate the cost of systems and administration cost to determine the set up and on-going costs to support alternative rate options.

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[15] FortisBC, *Retail Choice, Price Comparison,* website url: http://www.fortisbc.com/NaturalGas/Homes/CustomerChoice/ComparingHowRatesAreSet/PriceComparison/Pages/default.aspx (accessed: January 2014)

[16] Rates vary depending upon the terms and conditions. The lower rates are fixed price rates, and the higher rates include green energy attributes.

[17] The Company's allowed cost of capital and operating expenses are embedded in the Midstream costs of the customers' bills.

Second, there is the possibility that the migration of customers back to FortisBC signals a general lack of interest in special programs. It would be costly to invest time and resources into new customer rate options that may not attract enough critical mass of customers. Therefore, it would be very important for FortisBC to query customers more specifically, and provide sample pricing representative of current forward market prices, option costs, and administrative charges, to ensure there was enough interest to launch the alternative rate options.

Third, there are migration issues and associated termination fees to consider. Once customers are signed up in an alternative rate program they are contractually committed and hedges are executed for their account. With 3 and 5 year programs, the utility is hedging considerably far into the future, so the utility would want to structure some sort of termination fee to cover possible hedging losses if customers chose to leave the program. The farther forward in time the program, the more substantive the termination charge may be. The actual costs cannot be determined on a prospective basis because the size and direction of a future market move cannot be forecasted accurately.

Centra includes a Volumetric Risk Premium (VRP) in its fixed-price rates to cover such costs. In its 2008 approval of Centra's fixed-price offerings the Manitoba Public Utilities Board (PUB) set the VRP at 5%. In considering the VRP, the Manitoba PUB stated:

> "There are a number of factors that affect the volumes of gas consumed by customers: these include the weather, conservations efforts, customer behaviour, customer additions or subtractions, and attrition. Because of these factors, Centra will be at risk of either hedging too high a volume of gas or not hedging enough. In either case, the over- or under-hedged volume are then at risk to the changing market price of gas. [18]

It is difficult to predict if the 5% VRP will prove to be adequate or not to mitigate these risks of over- or under-hedging. Depending upon the total customer count sign-up, the percentage of customers wanting to migrate out of the program in the future, and the size and duration of a market price movement, 5% may not cover the hedging exposure. Customers are only likely to leave the program when market prices are falling, and the question is who would bear the losses in excess of a 5%. This uncertainty opens up complex issues that need to be resolved before a program launch.

[18] Manitoba Public Utilities Board, *In the Matter of Centra Gas Manitoba Inc. Fixed-Rate Primary Gas Services Application*, Order No. 156/08, 19-20.

Fourth, alternative rate options have set protocols. The offerings would not change with market conditions, and once a customer committed to an alternative rate program, it would be locked in to that program. This is in contrast to a FortisBC default portfolio where hedging could be adjusted for different types of market conditions and only a portion of the portfolio would be hedged. Fifth, as FortisBC's customer research indicated, a program of customer outreach and education may be necessary for customers to understand and consider effectively such optional programs. Developing customer understanding of tariff structures, market dynamics and cost analysis tools (to understand tradeoffs among options) could require significant dedication of time and resources.

Because of its management of pipeline capacity, storage resources and gas supply contracts, FortisBC has real-time information regarding changes in wholesale markets. The Company's gas supply team has access to many sources of market information and the staff is devoted full-time to gas supply logistics and planning. In contrast, very few of FortisBC's customers would have the same type of market knowledge or market insight. This is another argument for why customers might choose to delegate decisions relating to market risk and opportunity to the Company, as opposed to managing this on their own.

In total, there appear to be material implementation challenges that would need to be explored in more detail to confirm whether alternative rate options would be effective. An alternative approach to offering Fixed Rate and Cap Rate programs would be for FortisBC to implement price risk management tools in its default service. The Company already has the systems and infrastructure in place to incorporate hedges in its default commodity service.

In North American competitive retail markets, the model of the utility hedging a portion of its default service portfolio or offering an index-priced rate option is more common than a utility offering fixed rate or capped rate options. If the utility, stakeholders and the commission felt it was important to offer an index-based alternative to the programs offered by marketers and FortisBC's default commodity service with hedges, then FortisBC could possibly offer customers an opt-out option where customers could sign up for an index-based rate alternative rate structure. The customers could elect to not participate in FortisBC's default commodity service and participate instead in an 'at market' FortisBC alternative rate offering.

If FortisBC, stakeholders and the Commission wanted the Company to develop an 'at market' rate option, there would still be several administrative considerations. First, the Company would need to develop systems to account for supply and customers sales volumes in the alternative rate option. Additionally, the Company would need to educate customers about the available 'at market' alternative, to ensure customers understood the alternative rate option opportunity, commitment obligations, and risks.

There are benefits to offering an 'at market' or index-priced rate option as an alternative to offering a fixed rate option. Judging by historical customer participation in Customer Choice, a rate offering outside of FortisBC's default service is likely to attract a relatively small group of customers regardless of what pricing program is offered. It would be easier for FortisBC to manage index-priced supply for a small group of customers than fixed rate option or rate cap option. This is because the wholesale market transacts in standard size blocks of 5,000 to 10,000 GJs or MMBtu per day. With a larger portfolio, it is simpler to aggregate blocks of hedges needed for each month's hedging target. In a small portfolio, the hedging blocks are less granular and the Company may end up with excess hedges in certain months and not enough hedges in other months, which adds risk exposure. Additionally, in a small portfolio, the effect of any one customer or group of customers migrating out of the rate option poses greater portfolio management challenges than in a large portfolio. Last, if FortisBC offered an 'at market' rate, this would not put FortisBC in direct competition with the third-party marketers. In contrast, if FortisBC were to offer a fixed rate option to customers, this would directly compete with third-party marketers.

Part IV – Developing a Price Risk Management Program

A price risk management program begins with understanding customer risk tolerance. Following this, a utility can set program objectives, which will lead to strategies, program design and selection of tools[19]. Having decided upon program design, a utility must then decide how the program shall be implemented. Last, the final element is how to determine hedging effectiveness.

Customer Risk Tolerance

A strong risk management program starts with an articulation of the organization's risk tolerance. For a utility that hedges on behalf of customers, a risk tolerance would reflect the customer's perspective on rates. A customer risk tolerance can be defined as the level of rate increase customers can accept in absolute rate terms or in percentage rate terms. Once a customer risk tolerance is defined, price risk management targets by year can be developed. The customer rate tolerance is easy for all parties to articulate because it translates an opaque issue (how much to hedge) into transparent terms (customers do not want to see rates increase more than a certain percent).

Price Risk Management Program Objectives

A utility's price risk management program design must be consistent with the program objectives, with clearly articulated targets that are consistent with the risk tolerance. Price risk management objectives shape a utility's hedging strategies. Based upon the price risk management objectives, the utility can determine which hedging instruments would best fit the portfolio. The price risk management objectives need to take into account an organization's capacity to hedge (ex: financial constraints, counterparty arrangements, market liquidity and operational constraints).

Price risk management program objectives should be consistent with a utility's projected load requirements and supply requirements. The amount of supply required to meet load is defined by its load forecast, and the percentage to be hedged relates to the forecasted load requirements. The focus on physical operations and reliability are part of supply management and are important

[19] Part V – Price Risk Management Tools provides a description of the standard hedging instruments available to Pacific Northwest utilities, and a framework for how these can be used to implement different hedging strategies.

to consider in gas supply planning. In addition to physical supply risk management, there are risks associated with the price or cost of natural gas, which is the focus of this report. Price risk management program objectives must also align with customer needs and preferences. With respect to customer preferences, a price risk management program should take into account customer risk tolerance.

Price Risk Management Program Design

The size and scale of a price risk management program should be driven by the risk tolerance, the program objectives, and risk exposures within the supply portfolio. The price risk management program design will establish the hedging time-frame and the percentage hedged by year as these determine the size and scale of the hedging program.

A. Risks Mitigated

Utility portfolios include a number of different price exposures, including market price risk, locational price risk, load uncertainty, and credit risk. A robust price risk management program will address all these risk exposures:

- **Market price risk** – Market price risk refers to the exposure of the underlying cost of natural gas. This is the largest price risk exposure in gas utility portfolios. Fixed price risk can be mitigated with physical fixed price contract or fixed price swap (also sometime called "fixed for floating" swap).

- **Locational price risk** – Locational price risk (also referred to as "basis" risk) represents the risk inherent in a gas supply portfolio when a hedge is located in a different location from where the position to be hedged is sited. For example, if a utility were to hedge at an alternative location than at its receipt points, there would be basis risk (e.g. gas supply not purchased at or tributary to pipeline receipt points). In physical markets, purchasing supply at the location where the utility is short can mitigate the risk. Additionally, a utility can manage its locational price risk by managing price volatility at the major market hubs and primary receipt points associated with its transportation and storage assets. Financial instruments to hedge locational risk include basis swaps and basis futures.

- **Load uncertainty** – Because of load uncertainty, there is additional price exposure in gas utility portfolios. Weather uncertainty and associated volumetric variability risk can be managed with storage and incremental purchases and sales. Storage allows a utility to manage supply reliability throughout the winter season and to protect customers from extreme spot market price volatility. When spot prices are higher than the weighted average cost of gas (plus transportation and carrying costs), a utility can withdraw from storage as opposed to purchasing spot supply. Many utilities have a storage policy to withdraw gas during the winter season to ensure adequate supplies through the peak months.

- **Credit risk** – A utility's hedging program must be sized appropriately for the organization's capacity to hedge (ex: financial constraints, counterparty arrangements, and market liquidity). It is very important the utility have adequate credit capacity to hedge customer risks because market conditions can change quickly and a utility might need to post collateral as prices move. Counterparty non-performance risk and credit default risk also need to be monitored carefully, through a credit risk policy, counterparty credit limits and concentration risk limits.

B. Time-frame and Volume Percentage Hedged

A utility has two 'levers' to manage the scale of hedging in the price risk management program: the hedging program time-frame and the percent of the portfolio that will be hedged. The common utility practice is to layer in hedges over a period of time, to hedge against rising prices and to smooth rate volatility for customers. A utility can narrow the range of gas supply costs by hedging a fairly high percentage of the portfolio in the short-term, with a lower volume hedged in the medium-term and long-term time periods. The benefit to the layering approach is that it connects rate years, so that the subsequent rate year relates to the previous rate year, as a portion of its hedges are executed at the same time. In this way, the up-coming rate year is less likely to diverge materially from the previous rate year.

Hedging Protocols

Many utilities have employed programmatic hedging programs, where specific volumes are executed on pre-determined dates, so that hedges are executed ratably until the delivery month. This is sometimes referred to as "dollar cost averaging", and the intent is to average hedge costs over a period of time. Utilities instituted programmatic hedging programs to simplify the administrative process and make it easier for external parties to understand the program, and therefore reduce regulatory risk. But, the chief problem with programmatic hedging is that it applies one hedging strategy to all market conditions. And, programmatic programs have come under more scrutiny in recent years as a result.

The other end of the spectrum is to employ discretionary hedging, which is more subjective than programmatic hedging. There are typically no set timelines or volume requirements. The benefit is that the utility can be more opportunistic to changing market conditions. But the negative element is that discretionary hedging is less transparent and can be difficult for the utility to defend if hedging protocols are not documented well. There are several ways to apply structure to discretionary hedging. One is to define what triggers or decisional criteria will be applied for the timing of hedge execution, the amount hedged and the instruments used for hedging. Examples of triggers are "at risk" metrics measuring potential risk exposure and fundamental market analysis.

Figure 14 - Comparison of Programmatic and Discretionary Hedging

	Programmatic	Discretionary
Key Elements	• Objective • Hedging at predetermined dates • Requires compliance with guidelines • Benefits: very transparent, easy to track, can be done with a small staff and easy to document • Cons: passive, mechanical and less responsive to market conditions	• Subjective • No set timelines • Requires robust market analysis and decision-making • Benefits: allows the company to be more opportunistic to changing market conditions • Cons: less transparent, more difficult to understand, requires strong documentation process

Typical Approach	• Formalize time frame and volume guidelines to hedge • Determine volumes to be hedged by a certain time frame • Use a laddering approach for "Dollar Cost Averaging"	• Allow discretion about when to hedge • Develop pre-agreed upon triggers for hedges • Agree what triggers shall be used for hedging

Aether recommends utilities employ a blended programmatic and discretionary hedging approach, where hedging targets are established for a defined time horizon and the utility has discretion about when and how it executes the hedges to meet the targets. The timing of hedges is driven by fundamental market factors and other triggers such as using historical price targets or implementing an at-risk methodology to reduce risk exposure in the portfolio. The blended approach provides a defined time frame and range of volume to be hedged with discretion in how the hedging is executed. For instances, different types of hedging instruments might be used in different types of market circumstances. Additional information regarding what hedging tools to use in different market conditions is included in Part V – Medium-Term Price Risk Management Tools.

Program Effectiveness

Price risk management program effectiveness can be determined using several techniques. There is often a tendency to compare the hedged gas costs to the spot market prices. This data can be helpful for examining the opportunity cost of hedging, which should be considered in a discussion of setting an overall risk tolerance. But, as a means of assessing price risk management program effectiveness, the analysis is flawed for organizations that have a small customer rate risk tolerance. That is, comparing hedged price to spot price is not a relevant or fair analysis when *not hedging* is an unacceptable path given the organization's risk tolerance.

Sometimes this tendency to look at hedged cost relative to spot market cost occurs because utilities have confusing risk policies. In an effort to cover all bases, a policy might state the utility will manage against price increases while looking for opportunities to benefit from market price decreases. But there is an inherent conflict in trying to protect against negative market price impact while also optimizing for lower market prices. This can technically be done, but only at great expense. As discussed later in this report, a utility can use call options to have no opportunity cost, but these can be costly. An alternative strategy to take advantage of falling market prices is to develop a view that market prices are going to fall and decide not to hedge.

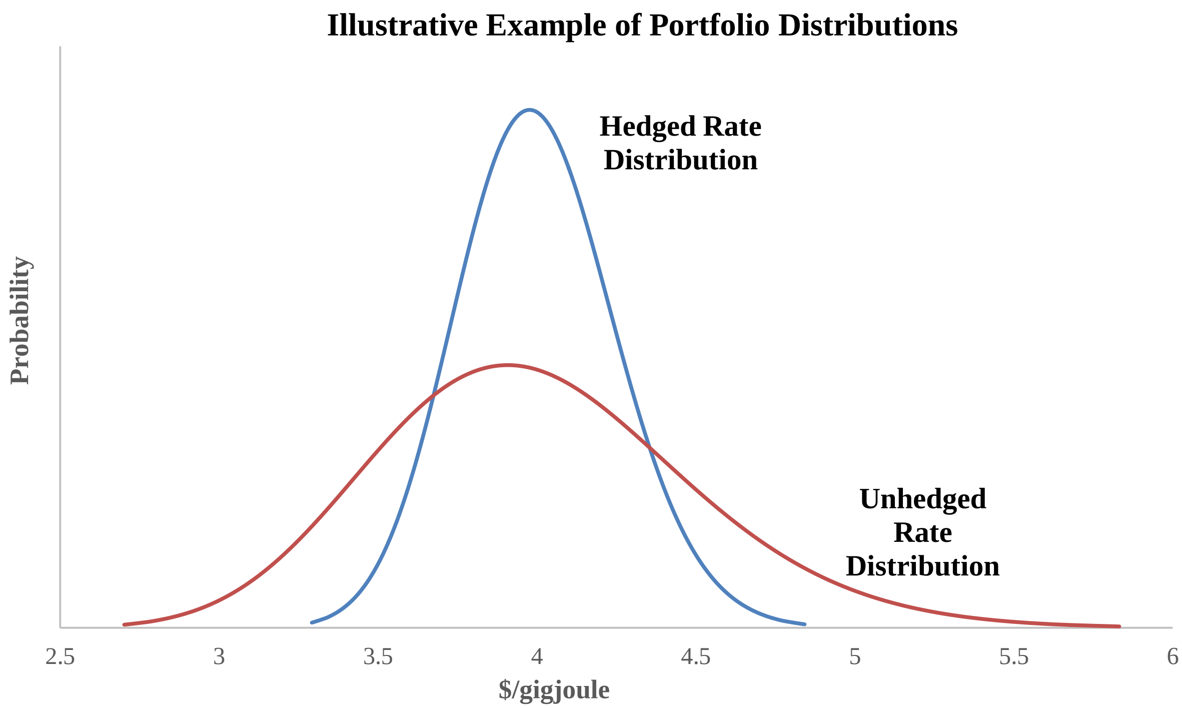
But to not hedge leaves customers open to volatility in market prices. In this respect, to not hedge is a form of speculation.

There are more appropriate techniques to measure price risk management program effectiveness that range from hedging execution to risk mitigation. The first is to examine the hedging execution prices relative to the market prices at the time of execution, which is appropriate for examining the utility's ability to execute hedges at close to the forward market. A second technique is to measure how the hedges compared relative to budget and historical forward curves, to understand what happened in real life compared to the assumptions built into the initial forecast; this helps improve future forecasting.

A third approach is to review what was known and measureable at the time the hedging plan was executed, examining the fundamental market analysis from that point in time. By tracking this, it is possible to see how the utility adjusted to new market information. In this context, an organization's ability to respond to market information speaks to the strength of its hedging program. This type of analysis is sometimes conducted in state regulators' reviews of investor-owned utilities' hedging programs. The review examines the hedging documentation associated with hedging execution. The objective is to ensure the utility's hedging activity was consistent with its risk policy as well as then-available information about market supply and demand factors. A fourth approach is to assess how much risk exposure was mitigated through price risk management. This could be done by modeling the portfolio without hedges, to see the full range in potential power and fuel costs, and then modeling the portfolio with hedges to review the differences.

When a commodity portfolio with hedging is compared to one without hedging, it is possible to see the effect of the price risk management strategy. A scenario analysis will demonstrate the reduction in the range of potential gas commodity cost, both in terms of reducing the risk exposure to rising prices as well as the larger opportunity cost associated with hedging. It can also help show how the cost of the hedge affects the expected value. Figure 15 illustrates how this might look. The X-axis represents the distribution of scenarios generated in a Monte Carlo analysis, where each scenario represents a different market price simulation. The Y-axis measures probability.

Figure 15 - Distribution of Gas Costs With and Without Hedging



The type of price risk management program and scale of hedging changes the shape of the curve. In Figure 15, the red distribution curve ("Unhedged Rate Distribution") indicates a fairly wide range of potential outcomes from a low of $2.70 per gigajoule to a high of $5.80 per gigajoule. It also demonstrates that the probability of gas costs being at the base case (the mean) is not very large. In contrast, when hedges are executed, the "book-ends" between the highest and lowest gas cost in the "Hedged Rate Distribution" show a more narrow distribution of potential outcomes. The blue distribution curve ("Hedged Rate Distribution") illustrates a commodity portfolio with hedges, where the range has narrowed to $3.30 per gigajoule to $4.80 per gigajoule and there are more scenarios closer to the base case of approximately $4.00 per gigajoule. In other words, the probability of gas costs being at the base case (the mean) is higher in the Hedged Rate Distribution Portfolio. In this respect, stochastic modeling allows the utility to see a potential range of outcomes relative to the base case (the mean) and how the base case and the shape of the distribution change with different types of hedging strategies.

Part V – Medium-Term Price Risk Management Tools

Utilities have access to several risk management tools that can be used to reduce customer rate volatility and mitigate risk of increasing gas costs. Each tool has different uses, so a portfolio of tools is ideal for achieving price risk management objectives. Figure 16 below summarizes different tools' ability to smooth rate volatility and to mitigate price short-term and medium-term price risk.

Figure 16 - Tools to Smooth Rate Volatility and Mitigate Price Risk

Risk Management Tool	Smooth Rate Volatility	Mitigate Risk of Rising Costs	Time-frame
Short-Term:			
Rate Structures	Yes	No	Quarterly to 1 year
Gas Storage	Yes	Yes	Summer to winter
Medium-Term:			
Physical Fixed Price	Yes	Yes	1 month to 3 years
Financial Instrument	Yes	Yes	1 month to 3 years

The size and scale of a utility price risk management program should be driven by what type of risk the utility wants to mitigate within its supply portfolio. Typically utilities design their price risk management programs to meet one of the following objectives:

- Fix (lock in) customer rates
- Keep rates within a band
- Protect against price spikes

The three objectives above are separate mitigation strategies to address the risks of rising market prices, and there are subtle differences between them that drive different hedging strategies and hedging program design. For example, if the objective were to fix customer rates, the utility would lock in the gas supply costs for customers by hedging a very high percentage of the portfolio, with fixed price contracts. If a utility were comfortable with a wider band for rates (implying a higher risk tolerance), the utility could employ a lower hedging percentage and hedge with fixed price. Alternatively, it might use a collar to put a band around gas costs. To protect against price spikes, a utility could purchase out of the money call options. These price risk management instruments are described in more detail below.

There are a multiple price risk management instruments and the protection each offers is contingent upon what occurs in the market. The price risk management objective and the anticipated market price trend determine which instrument the utility will select. The selection of tools is also affected by the availability and cost of the various instruments.

Gas Storage

Natural gas storage is a physical hedge commonly used by natural gas utility companies. Natural gas is injected during lower-priced spring and summer months and then withdrawn during periods of high prices, typically November through March. Utilities plan withdrawals to ensure adequate supply during the peak winter period.

The most common form of underground storage is depleted natural gas reservoirs where useable natural gas is depleted and the field can be developed for storage. Given these depleted reservoirs have previously held natural gas, they can be retrofitted and refilled by injecting natural gas. A second underground storage structure is a salt-dome cavern which is flushed with water to create storage caverns. The salt dome formation is more common in the U.S. Midwest states, whereas depleted storage reservoirs are found in the Pacific Northwest, the Rockies and the Western Canadian Sedimentary Basin. A third form of underground natural gas storage is an aquifer, which is a water reservoir converted to gas storage. Aquifers typically require more cushion gas and are more expensive to operate. [20]

Another form of natural gas storage is an LNG storage tank. This requires less space than underground storage and is typically located near concentrated load areas or where there are distribution system constraints. However, LNG storage costs are higher than traditional

[20] Energy Information Association, *The Basics of Underground Natural Gas Storage*, August 2004, http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/storagebasics/storagebasics.html (accessed: January 2014)

underground storage since the natural gas must be pressurized at very cold temperatures to liquefy the natural gas. As a result, LNG is usually used as a "needle-peaking" resource for extreme peak needs, and typically represents a small portion of a utility's total storage capacity. Emerging demand for LNG as a transportation fuel may drive down the cost of LNG storage in the future. With a larger demand base, new LNG storage may become more modular in design and fabricated on a larger scale.

Natural gas storage can be owned and operated by a utility or leased from an owner-operator. Storage assures a source of reliable supply to meet customer demands during periods of supply constraints. Combined with winter base-load purchases, storage is highly effective in meeting peak load demands during periods of cold weather, where customers would otherwise be exposed to sharp increases in spot prices. Therefore, storage is critical for providing both reliability and rate stability for customers. As a price risk management tool, storage only serves as a short-term hedge, as summer injection gas is carried into the following winter. At times, some inventory is un-used at the end of the winter, and that remaining inventory carries over to the next rate year as a hedge.

With respect to valuing storage, there are operational elements as well as price considerations. The operational analysis is driven by peak load planning requirements and alternatives. Because natural gas demand is highly seasonal with its greatest demand coming from heating, the utility must have enough winter capacity to meet peak load requirements. With respect to alternatives, incremental storage may be less expensive than year-round pipeline transportation capacity that might only be used in winter and then under-utilized the balance of the year.

With respect to contracting market area storage, the key cost considerations are the monthly storage rate, the injection and withdrawal cost (including fuel loss), incremental transportation costs to transport injection gas into storage and moving withdrawal gas to the city-gate, and carrying costs. Utilities typically compare the storage cost and other costs to the price differential between winter and summer prices (historical and forward market seasonal price relationships). The visible market spread is sometimes referred to as the "intrinsic" value (the value that can be locked in with market prices). There can also be additional option value to storage if there is flexibility in injection and withdrawals schedules ("extrinsic" value). Most extrinsic value is realized in the spot market when the utility can inject and withdraw opportunistically.

Physical Fixed Price

A physical fixed price contract is an agreement with a counterparty to deliver a specified amount of physical gas at a specified point in time, to a pre-defined location at a fixed price. These are commonly used by utility companies to hedge against rising prices. Typical terms for physical fixed price contracts can vary greatly ranging from one month to greater than five years.

Physical fixed price contracts are effective in mitigating price exposure and meeting base-load supply needs. From the customer's point of view, they are very effective at providing reliability and rate stability. Generally, transaction costs are low and pricing is visible within a liquid window of time. Liquidity can vary greatly by location but generally price visibility is available from 1 month to 3 years. Typically, a highly rated utility receives more open credit from counterparties with physical fixed price transactions than with financial transactions.

The risks associated with using physical fixed price contracts are force majeure events, counterparty credit default, and liquidity constraints. Force majeure events that prevent the supplier from delivering gas occur relatively infrequently, and gas storage can be a back-up supply. Diversifying transactions with several high quality credit grade counterparties can mitigate counterparty credit default risk. Credit threshold amounts and collateral posting requirements can be negotiated in physical fixed price contracts or associated enabling agreements. Transacting at a liquid market with multiple buyers and sellers can mitigate liquidity risk.

The benefit of a fixed price contract is that the cost is locked in. But the downside is that there is no opportunity to benefit if market prices fall below the price at which the fixed price contract is executed. When a utility wants to lock in a specific cost, the low transaction cost and price certainty are important benefits to a fixed price contract. If a utility believes prices are more likely to rise than fall, and it has a specific price target or a low risk tolerance, then it will execute a fixed price transaction to hedge price risk.

Financial Instrument

A. Fixed Price Swap (also called "Fixed for Floating" Swap)

As an alternative to the above, another method to hedge fixed price risk is to use a financial instrument called a fixed price swap. Physical suppliers often prefer selling at an index relationship, and a different set of counterparties are willing to be market-makers in the financial swap market. A utility can buy physical gas that is priced at a posted index price from a marketer or producer and execute a financial swap that fixes the price of this index for the length of the contract. At markets such as AECO and Rockies, sometimes a fixed price swap can be transacted easily. But when there is not much liquidity in the fixed price swaps at certain locations (which sometimes is the case at Sumas), the utility may be able to create a similar hedge with a Henry Hub fixed price swap and a basis swap contract.

A fixed price swap mitigates price exposure through a financial settlement. After the benchmark index price has been posted, the parties compare it to the original contract price. If the index price is higher than the contract price, the seller makes a financial payment to the buyer. And, if the index price is lower than the contract price, the buyer makes a financial payment to the seller. Often there is more liquidity (more market participants and higher trading volumes) in financial swaps. As a result, it can have a lower transaction cost, and may be executed more quickly, than physical fixed price supply. But it doesn't provide physical supply, and the utility has to still acquire physical supply from a supplier. Liquidity can vary greatly by location but generally price visibility is available from one month to five years. From time to time counterparties will agree to transact as long as ten years into the future.

The risks associated with using fixed price swap contracts are counterparty credit default, new CFTC regulatory compliance, and liquidity constraints[21]. The swap contract provides slightly better price protection than the physical fixed price transaction since there is no issue of a force majeure event affecting delivery of supply. Diversifying transactions with several high quality credit grade counterparties can mitigate counterparty credit default risk. Transacting within a liquid market with multiple buyers and sellers can mitigate liquidity risk. And, preparation and good risk management practices should protect a utility from CFTC non-compliance risk.

With respect to credit terms, they differ depending upon whether the utility is transacting bilateral contracts directly with counterparties or clearing swaps through a clearing firm. Credit threshold amounts and collateral posting requirements can be negotiated in a bilateral swap agreement. Entities with strong credit ratings historically have been offered a certain level of open credit (threshold) before margining is required by the counterparty for negative mark to market.

Typically, a utility has a great deal less open credit if it chooses to clear transactions with a clearing firm. Per the CFTC rules for cleared transactions, the utility would have to post initial margin along with variation margin associated with mark to market movements affecting the value of its contracts. The positive side is that there is minimal counterparty risk with cleared

[21] As part of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd Frank Act) passed by the U.S. Congress in 2010 as an effort to implement financial reforms, the US federal agency called the Commodity Futures Trading Commission (CFTC) was charged with oversight of financial derivatives (also referred to as "swaps"). As a result of the Dodd Frank Act, the CFTC has written rules to regulate the swaps marketplace. For more information, see: http://www.cftc.gov/lawregulation/doddfrankact/index.htm

swap transactions, since the CFTC has strict rules for maintenance of customer funds by clearing firms.

In response to the more significant reporting, capital, risk management and end-user service requirements for swap dealers and major swap participants associated with new CFTC swaps regulation, Intercontinental Exchange (ICE) recently launched futures contracts that have similar characteristics to swaps at geographic locations like AECO, Sumas or Rockies. Therefore, an alternative to a cleared fixed price swap is to use futures for hedging. To mimic a cleared fixed price swap, the utility would purchase Henry Hub futures and basis futures at a location such as AECO, Sumas or Rockies. A futures contract would have similar margining requirements as a cleared fixed price swap, but transaction costs may be lower since futures traders are not subject to as many compliance requirements as swap dealers have when transacting with end-users.

As with a fixed price physical contract, the benefit of a fixed price swap or a futures contract is that the cost is locked in. But the downside is that there is no opportunity to benefit if market prices later fall below the price at which the fixed price swap or futures contract is executed.

B. Call Option

A call option is another way to hedge against increases in natural gas prices. It can be structured as either a financial instrument or as a physical contract, but most often is a financial instrument. A call option gives the buyer the right, but not the obligation, to buy gas at a fixed price at a specified point in time, location and price (the 'strike' price). The benefit of a utility using a call option as a price risk management tool is that customers benefit if the market price falls.

However, this benefit comes at a cost, which is the premium paid for the call option. At the time of purchase, the utility pays a premium to the counterparty selling the call option. The amount paid is determined by several factors: 1) strike price relative to the forward price; 2) amount of time to expiration of the call option; 3) expected market volatility; and 4) interest rates. The farther forward in time the option is, the higher market volatility is, the closer the option strike is to the forward market price, and/or the higher the interest rate, the more expensive the call option premium.

Some utilities purchase 'out-of-the-money' call options to protect against significant upward movements in prices. This is potentially attractive when there is a relatively high risk tolerance. A utility might use call options as a hedge strategy when it wants to protect against sharp increases in price, but wants to retain the benefit if market price falls. Call options are attractive instruments when volatility is low and the call option premiums are not expensive.

As with a fixed price physical contract or a bilateral fixed price swap contract, there is some counterparty credit default risk if the call is a physical option or a bilateral financial option. The buyer pays a premium to the seller at the time the call is purchased, and then the buyer expects the seller to honor the call option if the market price rises above the call strike price (either through physical delivery or financial payment). If a call is transacted as a cleared financial instrument, then the utility has the credit protection of the clearinghouse and clearing firm. The initial and variation margin requirements would be much less with a call than a fixed price swap as the mark to market would only apply to the value of the premium. There is limited liquidity in call options, so it is advisable to transact at strike prices where trading volumes are greater.

C. Collar

A collar (also called a "fence") combines a purchase of a call and the sale of a put (to finance the purchase of the call). The strike prices for the call and put can be set to where there is no premium cost for the buyer. If market price increases, the utility is protected at the strike price of the call. If market price falls, the utility participates in the declining prices until the market price hits the put strike price (also called the floor price). The collar puts a range on the price, so that the utility is purchasing somewhere between the call strike price and the put strike price. It can be structured as either a financial instrument or a physical contract, but most often as a financial instrument. Utilities sometimes use collars as an alternative to fixed price contracts, to hedge six to twenty-four months forward in time.

The benefit to using a collar is that the utility can participate if prices fall from current forward market levels, up to the level of the put strike price. This can be attractive if markets are expected to be range-bound. Further, because a call is purchased and a put is sold there is no upfront premium paid, unlike when purchasing a call option. However, the tradeoff is that if prices rise, the utility would have been better off purchasing a fixed price contract, since the protection in the collar doesn't start until prices rise above the call strike price. Conversely, if prices fall below the put strike price the utility may have been better off purchasing a call option.

The setting of the strikes for the call in a collar should be consistent with the utility's risk tolerance. For example, if the utility feels comfortable with prices moving no more than 5% from current levels, and the forward market is currently at $5.00 per MMBtu, then the call strike would be set at $5.25. The floor is then determined by finding a put strike whose premium is the same cost as the premium for the $5.25 call.

Although there is no upfront cost associated with a collar, typically the distance from the "at-the-money" forward price and the call strike is greater than the "at-the-money" forward price and the put strike. Thus, the relative value to the utility of the call purchased may be less than the value of the put sold due to transaction costs and volatility skew. Often, utilities transact collars with a single counterparty, which reduces liquidity should the utility want to re-structure the instrument or change it to a different type of hedge. One way to mitigate that is to transact the call and put separately in order to simulate a collar. It is advisable to transact at the most liquid market locations, using call and put strike prices with the largest trading volumes. This may result in a small net premium paid or received to structure the call with more liquid strike prices.

As with a financial fixed price swap or a financial call option, the utility has the option to transact the collar as a bilateral transaction or a cleared transaction. There is counterparty protection with a cleared collar transaction, but the utility will have initial margin and variation margin to pay on the relative value of the puts and call premiums. If the market price falls below the put strike, the margin call will be similar to a fixed price swap. If the swap is transacted bilaterally, the counterparty's credit requirements on the utility will be similar as those for a fixed price swap.

The collar is an instrument that can be effective when the utility feels prices will remain within a trading range, and would like to set hedging protection outside the range. Collars are useful when a utility has a risk tolerance that can accommodate higher prices than the current forward market price and would like to retain some downside price opportunity. Collars can be attractive price risk management tools if the call strike can be structured at a fair value relative to the put strike.

Medium-Term Price Risk Management Considerations

A utility has two levers in medium-term price risk management: the hedging instrument and the amount to be hedged within the minimum and maximum targets. In an environment where market prices have fallen and have been declining for an extended period of time, Aether suggests a utility hedge at the high end of the volume range with fixed price purchases. The reason is that there may be minimal downside opportunity at that point, and the fixed price has the lowest execution cost. In an environment where natural gas prices have risen from recent lows, and are higher because of short-term fundamentals (such as colder than normal winter weather) and longer term production and demand trends may cause market prices to revert to a lower level, then Aether recommends using a collar structure and hedging at the mid-level volumetrically. Then if prices fall back to lower levels, Aether recommends adding fixed price hedges. And, when market prices are historically high, Aether recommends hedging short-term with fixed price or call options at the low end of the volumetric range and using collars for the medium-term hedging at the low end of the range.

Part VI – Medium-Term FortisBC Portfolio Analysis

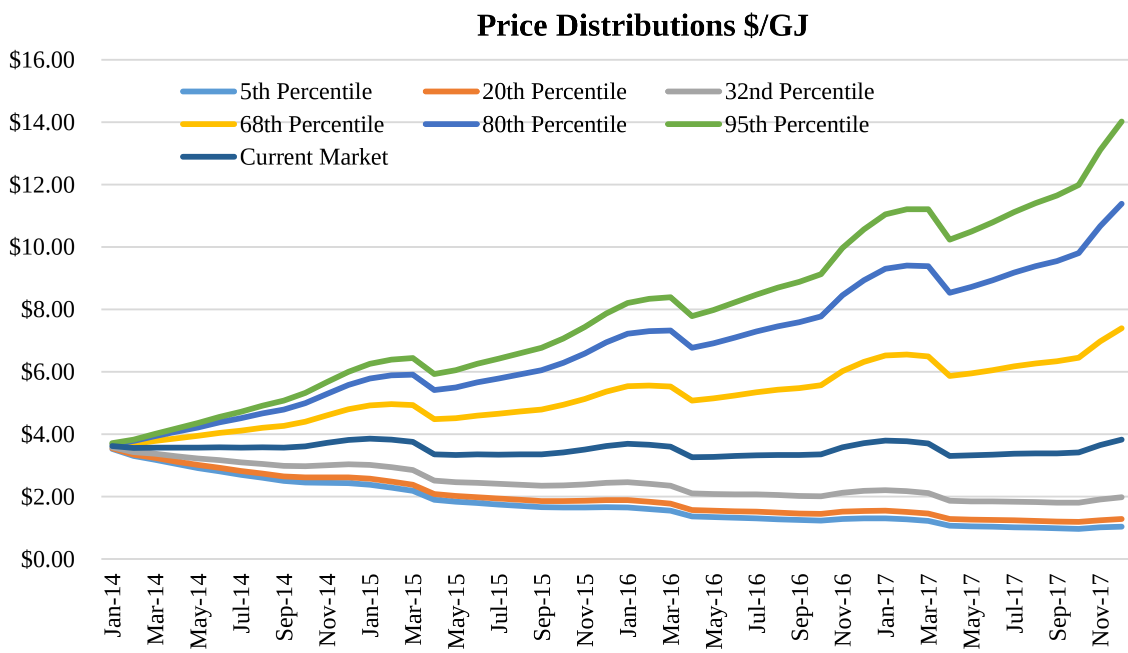
Aether modeled FortisBC's portfolio to test the effect of different medium-term price risk management tools (hedging instruments), using a number of scenarios. As a starting point, Aether used the Company's projected load requirements for the Gas Year November 2014-October 2015, where there are no physical fixed price gas purchases or financial instruments executed. Then, Aether tested the portfolio for six different load scenarios and six different market price scenarios.

Aether modeled the impact to the portfolio using four different price risk management targets: 0% (no hedging), 25%, 50% and 75%. And, for these four price risk management percentage targets, three types of instruments were tested: fixed price financial swap, call option, and collar. The objectives for conducting the portfolio analysis were to: 1) determine potential risk exposures for FortisBC's customers associated with different market price movements and 2) illustrate the trade-offs between cost of hedging, risk protection and opportunity cost of different price risk management instruments.

The price scenarios came from a price distribution Aether developed with forward market prices and forward month implied volatilities as of December 16, 2013. This represents the degree that market prices could move from December 16, 2013 based upon current forward market volatility, derived from forward market natural gas options. Forward market volatility is a measure of how the market perceives uncertainty in price. A price distribution will change as the forward market prices and the forward volatility curves change. For example, when market volatility is higher, the price distribution is wider. The forward volatility used in the analysis for the months of November 2014 - October 2015 averaged 22.4%.

Aether used several levels of price change from the price distribution analysis for the tables: 5% percentile, 20% percentile, 32% percentile, 68% percentile, 80% percentile and 95% percentile. The 95% percentile is a commonly-used metric by utilities and other energy industry companies for value at risk calculations. The 95% percentile represents a 1:20 chance of a market event occurring. Natural gas prices are relatively low, and the amount they can continue to fall is finite (until producers shut in well production, which is at $1.50-2.00 per gigajoule). In contrast, natural gas prices have much more price upside risk, which is sometimes referred to as a log normal price distribution. The price distribution chart is shown below.

Figure 17 - Natural Gas Price Distribution for FortisBC Portfolio Analysis



Aether made several simplifying assumptions about the portfolio and the CCRA rate when conducting the analysis. The CCRA rate assumes no deferral account adjustments. In terms of the value of the call option and the collar, the analysis assumes these are acquired as price insurance and are held to expiration and either expire in-the-money or at zero value (depending upon market price). The fixed price financial swap price used in the portfolio analysis was the closing settlement price. The call option used was a $.50/GJ out-of-the money call option and the premium cost was calculated using implied volatility and a Black-Sholes option model. The collar structure used in the portfolio analysis had a $0.50/GJ out-of-the-money call option and $0.35/GJ out-of-the-money put option based upon market pricing Aether has observed on collar structures. Last, the discounting of forward market prices was done assuming LIBOR interest rate costs.

Below are two summary tables of the portfolio scenario testing results, assuming normal load. The full analysis is provided in Appendix A: FortisBC Portfolio Analysis Detail, where all combinations of the different load scenarios and price scenarios are presented. [22] The first table

[22] The Appendix tables include some results that are more extreme than the summary results above, because adding load variability to price variability extended the high and low scenarios. Because the focus of this report is

shows the CCRA rate impact in percentage change from the current CCRA rate. A negative percentage indicates cost decrease for customers and a positive percentage indicates a cost increase. The upside risk exposure is greater than the downside opportunity because of the shape of the price distribution where there is greater upside risk than downside risk.

Figure 18 - Rate Exposure Mitigation (%)

Gas Year 2014/2015

Exposure Defined by Rate Impact % (Change from Base Case)				
	Unhedged	**25% Hedged**	**50% Hedged**	**75% Hedged**
Fixed Price Hedge				
95% Percentile Price Increase	70.7%	53.0%	35.3%	17.7%
5% Percentile Price Decrease	-40.9%	-30.7%	-20.5%	-10.2%
Call Option Hedge				
95% Percentile Price Increase	70.7%	57.7%	44.8%	31.9%
5% Percentile Price Decrease	-40.9%	-39.6%	-38.3%	-37.0%
Collar Hedge				
95% Percentile Price Increase	70.7%	56.4%	42.2%	27.9%
5% Percentile Price Decrease	-40.9%	-33.1%	-25.2%	-17.4%

Depicting the effect of hedging or not hedging in this fashion allows the Company to review the impact on customers in terms of percentage change in rates. Aether recommends this approach in order to define risk exposure in terms that customers and stakeholders can understand.

The use of 95% and 5% percentile represents a 1 in 20 chance of occurrence for either price scenario. If the Company wanted to use a more likely event it could monitor the risk exposures at lower percentiles. This analysis can be used to decide how much to hedge. For example, based upon this portfolio analysis and FortisBC's 2005 customer survey results indicating that on average customers could accept a 16% rate increase, Aether recommends FortisBC develop a hedging target of 75%. However, it would be important to continue to survey customers every couple of years to see how their risk tolerance shifts, given economic conditions, cumulative rate impact over multiple years, and other external factors. In that manner, FortisBC could take new customer input to refine its price risk management program.

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predominantly on price risk exposures, the tables in the body of the report assume normal load. The load scenarios in the Appendix were: +1% above normal, +3%, +3% summer/5% winter, -1 %, -3% and -3% summer/-5% winter.

Additionally, it is important to consider the rate risk in absolute dollar terms. In other words 16% rate tolerance can translate into different absolute numbers if the market is at $3.00 per gigajoule versus $6.00. So, it would also be important to gauge customers' risk tolerance in dollar terms. The second table below in Figure 19 illustrates the impact in $/gigajoule to show the impacts in absolute terms. A negative number indicates cost decrease for customers, and a positive number indicates a cost increase.

Figure 19 - Rate Exposure Mitigation ($/Gigajoule)

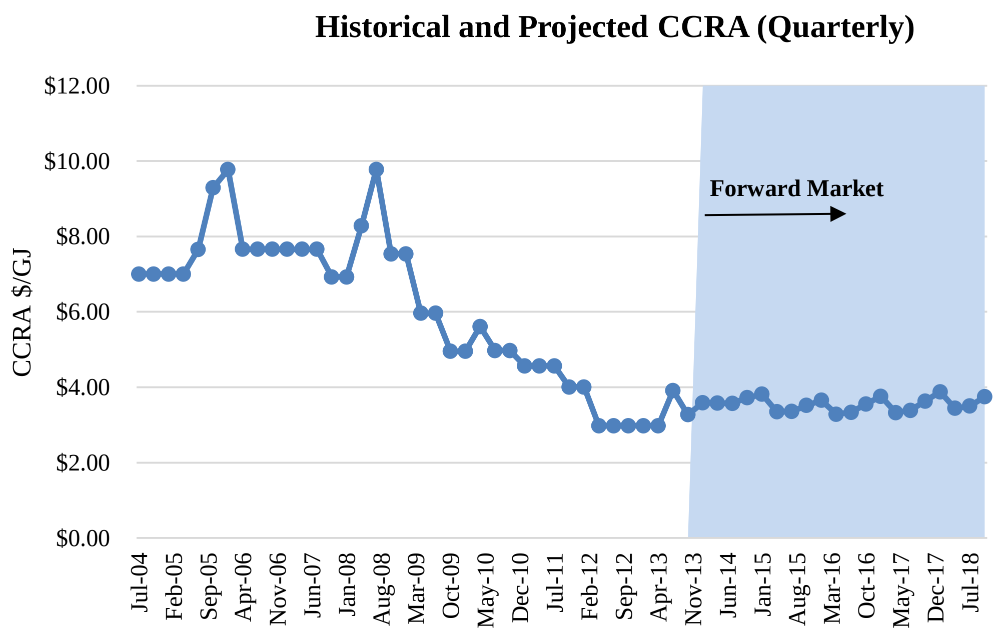
Gas Year 2014/2015

Exposure Defined by Change in CCRA Rate $/GJ (Change from Base Case)				
	Unhedged	**25% Hedged**	**50% Hedged**	**75% Hedged**
Fixed Price Hedge				
95% Percentile Price Increase	$2.58	$1.94	$1.29	$0.65
5% Percentile Price Decrease	($1.50)	($1.12)	($0.75)	($0.37)
Call Option Hedge				
95% Percentile Price Increase	$2.58	$2.11	$1.64	$1.17
5% Percentile Price Decrease	($1.50)	($1.45)	($1.40)	($1.35)
Collar Hedge				
95% Percentile Price Increase	$2.58	$2.06	$1.54	$1.02
5% Percentile Price Decrease	($1.50)	($1.21)	($0.92)	($0.64)

The table in Figure 19 defining exposure in $/gigajoule differential from the baseline CCRA rate is helpful for comparing and contrasting different strategies. In the 75% hedged column, in an extreme event where prices rose to the 95% percentile, the price risk management tool that offered the greatest price protection was the fixed price hedge (the CCRA rate only increased $.65 per gigajoule). The second most attractive instrument was the Collar, where the price protection began $.50 above the forward market price (there was no premium cost). The least attractive instrument in a high price scenario was the call option because there was a premium cost to acquire it, and the price protection began $.50 above the forward market. Conversely, in the event market prices fall significantly (the 5% Percentile Price Decrease), the call option is the most attractive, for it allows the customers to benefit from falling prices more than the collar or the fixed price.

It is important to put the portfolio scenario analysis into a historical context. Figure 20 below shows FortisBC's historical customer commodity rate to the left side of the graph, along with a projection of the CCRA rate (assuming 100% hedging). This was done to convert the forward market into a CCRA equivalent. If FortisBC elected to hedge 75% of the portfolio, then the actual cost would be higher or lower than the projected CCRA in the graph, depending upon whether actual prices moved higher or lower than the forward prices.

Figure 20 - FortisBC's Historical CCRA, Projected to July 2018



The above graph is the historical FortisBC monthly CCRA rate through October 2013, and projections into the future based upon forward market prices as of December 13, 2013.

The graph illustrates the potential opportunity for FortisBC to acquire medium-term to long-term supply at historically low rates. If the current forward market prices could be locked in through a long-term hedge, FortisBC could offer long-term low rates to customers, providing price certainty and rate stability. Additionally, if the hedge were executed as a physical purchase or in the form of natural gas production, then there would be an added benefit of long-term supply reliability. Given the emerging supply and demand factors in western Canada, securing physical supply could be important.

Part VII – Long-Term Price Risk Management Tools

Long-Term Fixed Price Physical Contract or Financial Instrument

A long-term fixed price physical contract or financial instrument is the same as the instruments described in Part V - Medium-Term Price Risk Management Tools, except the term of the agreement may extend to 5-10 years into the future. Typically, market liquidity is greater for financial swaps than physical fixed price, but for both there is a notable reduction in the number of participants and market liquidity more than eighteen months in the future.

Long-term fixed price contracts of five to ten years are not executed frequently because there are material counterparty credit concerns. The longer delivery period exacerbates the potential mark to market change which could trigger collateral calls by one party or the other. If market prices fell, the buyer (the utility) would have to provide collateral to the seller. And, if market prices rose, the seller would have to provide collateral to the buyer. The collateral call is calculated by determining the net present value of the future difference in market price movement times the remaining contract volume. Although the long-term forward price curve moves less than the short-term forward price curve, the remaining delivery volume could still be very large, which might result in significant collateral calls.

A high investment grade credit rating results in a higher credit threshold, so financially stronger counterparties are extended more open credit before collateral calls are made. As a result, long-term physical fixed price transactions are usually only transacted by high investment grade producers, reducing the availability of potential counterparties. Similarly, long-term financial instruments are usually only transacted with highly-rated banks.

Volumetric Production Payments

With a Volumetric Production Payment (VPP), the buyer pays a lump sum payment up front and receives a specific volume delivered for a defined delivery period. The VPP volume is conveyed through the sale of a limited volumetric over-riding royalty interest (i.e., a non-operating interest). The buyer makes a payment to the seller at the beginning of the delivery period for the net present value of the volume to be delivered over time. Once the producer has delivered the volume, the conveyed interest reverts back from the buyer to the seller. A producer will often use the VPP payment to finance new exploration and production.

Since 2006, banks have most often served as purchasers in VPPs with gas producers. As an example, Chesapeake Energy (Chesapeake) transacted 5 year to 20 year VPP transactions aggregating to $6.4 billion with Wells Fargo, Barclays and Morgan Stanley from 2007 to 2012. The structures look like loans that are backed with low-risk proved, developed producing reserves. At the time of the Barclay VPP in 2012, S&P rated the VPP notes at BBB, several notches above Chesapeake's corporate credit rating of BB+, illustrating the lower risk associated with the VPP. Other producers that have executed VPPs include Pioneer Natural Resources, Dominion Resources Inc., KCS Energy, GMX Resources Inc., and Obsidian Natural Gas. Aether is not aware of any Canadian gas producers who have entered into VPPs.

VPPs have been conducted in both rising and declining gas markets. The producer typically uses the proceeds for other investments. In this manner the VPP is part of a larger strategy to access capital. The producer is able to monetize certain assets and use the sales proceeds to invest in other investments.

The US Internal Revenue Service has determined that a VPP must be recognized as a debt obligation by the seller, and the rating agencies have adopted this in their ratings criteria. [23] Additionally the rating agencies place significant value on third party reserves estimates. When Standard & Poor's assesses a VPP, it examines how the reserves are monitored: "Although Standard & Poor's will evaluate transactions based on the reserve engineering provided by the Seller, Standard & Poor's generally will apply conservative estimates of future production without a second estimate from an un-conflicted party. Standard & Poor's believes that a competent engineer and acceptable report will consist of a thorough audit (rather than a review of reserve engineering processes) by an engineer with ample experience in the region of the burdened properties and full independence from the Seller".[24]

There are several benefits to a VPP. Given limited liquidity in the forward market, a VPP is a method to stabilize customer rates by hedging gas supply 5-20 years forward in time. And, the differential between the utility's cost of capital and the seller's hurdle rate may result in net present value cost that is more attractive on a levelized basis than a forward fixed price contract. The higher the credit rating of the utility relative to the producer's, the larger this benefit will be. And the delivery volume is fixed over the term of the agreement.

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[23] Standard & Poor's Criteria | Corporates | *Industrials: Volumetric Production Payments (VPPs) For U.S. Oil And Gas Exploration And Production Companies*, January 2009.
[24] Standard and Poor's Criteria | Corporates | *Industrials: Criteria for Rating Oil and Gas Volumetric Production Payment-Backed Transactions*, August 19, 2004.

The gas may be delivered to the buyer in the field or at a mutually agreed upon delivery point. The VPP is a firm delivery contract, usually subject only to force majeure events in the field or in route to the delivery point (and for which production is made up at a later date). Usually the seller, not the buyer, incurs production cost risks. Last, bankruptcy code provides some protection to VPP buyers since the VPP is recognized as a separate property interest from the seller's bankruptcy estate, providing the buyer a senior secured position in the bankruptcy process.

There are some limitations associated with VPPs. Because a VPP is a non-operating interest, the buyer does not typically participate in the life of the reserves or share in new drilling costs and associated production opportunities. With a VPP, a buyer assumes reserves risk, but this is mitigated in that the buyer usually has rights to production in the producer's proved producing properties. Further, the transaction could be structured where the amortization schedule of the VPP volumes matches or exceeds the expected production decline to ensure there is an adequate cushion through the term of the transaction.

Reserves Investment

A direct investment in gas reserves puts the buyer in the role of a gas producer. The buyer acquires a working interest with a share in production over the life of existing wells and all future wells in which the buyer participates. A reserves acquisition can be structured in different ways. For example, if the buyer participates in exploratory drilling with the producer as opposed to owning a share of a mature production field, there is greater risk but lower cost and more upside opportunity. This is called a "Carry and Earn" or "Drill to Earn" working interest, where the buyer contributes capital to new drilling. In this fashion the non-operating interest owner participates along-side the producer and other owners to retain the same future % ownership in the properties. The buyer and the producer's positions are aligned in terms of the decline curve and new production additions, as opposed to a VPP that gives the buyer a preferential position with respect to production. There are several examples of U.S. utility investment in natural gas reserves in Appendix C: Illustrative Utility Hedging Programs. Aether is not aware of any Canadian utilities that have invested in gas reserves. However, Encana has executed several joint venture investment agreements for Canadian reserves.[25]

[25] Encana has several joint ventures in Canadian gas producing properties: 1) farm-out agreements with KOGAS Canada Ltd., a Korea Gas Corporation subsidiary ("KOGAS"), 2) sale of a 40 percent partnership interest to Mitsubishi to jointly develop certain Cutbank Ridge lands in British Columbia, 3) sale of a 49.9 percent working interest to PetroChina to jointly explore and develop certain Duvernay lands in Alberta, and 4) sale of a 32.5 percent

Production rights in reserves are a tangible asset, and the rights can be purchased or sold, so the asset can be monetized in the future if required. Counterparty risk is significantly mitigated in comparison to a long-term purchase contract, as the counterparty risk is limited to the operating agreement. This risk is relatively limited since it is rare for an operator to not be the majority interest holder.

There are a number of benefits associated with acquiring reserves. For the buyer, the combined cost of the purchase of reserves and the estimated future production costs at the time of the deal is a significant discount on an NPV basis to a forward price strip (this differential usually represents operating risks and the producer's embedded margin).

Producers often purchase and sell reserves, in order to access new basins or change their operating profile. Sometimes producers sell reserves to raise cash, if they face financial constraints. They might also sell North American gas reserves in order to invest in oil producing properties or to acquire gas reserves in other regions. Additionally, some producers may sell producing properties to generate cash so they can acquire undeveloped properties or land leases. The latter are lower-cost on a per unit basis, and this could be a strategy to leverage their portfolio in the event gas prices rise materially.

The reserves buyer holds title to a physical asset as opposed to a contractual promise of delivery, so counterparty credit default risk is minimal. The acquisition of reserves provides natural gas supply long into the future, which helps with long-term rate stabilization. In a low interest rate environment, reserves can be financed inexpensively. Reserves are an asset that can be pledged as collateral or sold if this were required.

There is more volumetric variability in owning reserves. First, field production can vary on a daily or monthly basis, in contrast to the fixed volume in a VPP. Additionally, the value of reserves will move up and down with the forward price of gas. Reservoir engineers estimate the number of reserves every 1-2 years. Reservoir estimates of proved undeveloped properties are based upon the forward market price as a determinant of economically feasible production. If market prices rise from current levels, the value of the reserves investment increases not only from the higher value for current producing properties, but also for non-producing reserves that are now economic to produce at the higher market prices.

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gross overriding royalty interest to Toyota Tsusho in natural gas production from a portion of Encana's Clearwater Alberta resource play.
http://www.encana.com/about/strategy/joint-ventures.html (Accessed: January 2014)

There are greater operating risks associated with an operating interest in reserves as opposed to a VPP. The buyer of an operating interest in reserves has the same operating risks as the producer and relies upon the producer to manage them. This risk is mitigated because the producer holds a majority interest and their interests are aligned with the buyer to manage costs. A reserves owner is subject to future environmental regulation for the life of the wells. There can also be operational risks associated with reserves, such as water seepage in gas wells or failure for new drilling to yield high-producing wells.

The due diligence required for a reserves investment is significant. The buyer reviews reserve reports, title searches, field operations data, permits, royalty agreements, environmental regulation and tax obligations. Since the reserves buyer is responsible for paying taxes, royalties, and other related production costs, there are more administrative responsibilities with reserves ownership than with a VPP. But this can be mitigated by outsourcing the administrative work to the operator or another interest owner.

In terms of investment criteria, the operating history, experience, reputation, and financial stability of the producer is critical. Ideally, the producer will have an operating history in the field in which the utility will buy reserves. Additionally, the cost of production is important to understand; the lower the cost of the properties and the cost to produce gas, the less risk there is of future de-valuation of reserves. Well spacing allowed on the land is also a consideration for valuation purposes. If a higher density of wells is allowed (ex: shifting from one well per 20 acres to one well per 5 acres), this results in increased production over a shorter-time frame. Further, it is important for the buyer to understand the production costs such as variable operating costs, value of the excess liquids, processing costs and gathering costs.

The buyer will want to have the option to receive proceeds from the marketing of the production gas or to take the production in kind. The location of the field determines its market value. Moreover, the location at which the buyer takes title to production gas should be compared to where the buyer needs to purchase gas to serve customers. If the production is in a different geographical location, the buyer can manage this locational risk on a medium-term basis (1 to 3 years) using basis swaps or basis futures.

Long-Term Price Risk Management Considerations

There are distinct trade-offs when comparing and contrasting long-term price risk management alternatives, including regulatory treatment, cost, opportunity, and potential risk exposure. FortisBC should seek the expert opinion of an accounting firm, but Aether believes that the regulatory accounting treatment and cost recovery associated with volumetric production payment and gas reserves would be as follows:

- Volumetric Production Payment: The cost of the gas would be expensed and recovered in commodity rates for the relevant delivery year in which supply was provided to the Company. The VPP would likely be treated as a "regulatory asset", but Aether is not sure if the Company could earn an allowed rate of return on the volumetric production payment amount. It may be a question as to whether the BCUC viewed the VPP as expenditure or as an asset investment. Those determinations can vary widely among commissions. For instance, some allow returns on all regulatory assets and some allow almost none. One argument for treating it as an asset as opposed to an expense is that the utility would hold a non-operating interest in the producer's properties.

- Reserves: The initial investment in reserves and any subsequent investments would be included in utility rate base, and the utility could earn an allowed rate of return. The depreciation would be in accordance with the production decline curve. Expenses to extract the gas, process it and deliver it to the delivery point would be operating expenses.

The table below in Figure 21 identifies some other major considerations and suggestions for risk mitigation.

Figure 21 - Comparison of Long-Term Price Risk Management Tools

	Opportunity	Considerations	Risk Mitigation
Long-Term Physical Contract	Relatively easy to execute	Counterparty risk, 2-way margining; pass-through cost	Transact with strong investment grade counterparty; set threshold amount for margining
Long-Term Financial Swap	Relatively easy to execute	Counterparty risk, 2-way margining; pass-through cost	Transact with strong investment grade counterparty; set threshold amount for margining
Volumetric Production Payment	Difference in cost of capital; No margining by utility; fixed volume delivered over	Due diligence required; More complex to structure than a long-term	Structure with fixed production and delivery costs; select low risk properties/reserves to be

	the term; minimal counterparty risk; minimal production or environmental risks;	contract	committed to buyer
Reserves "Drill to Earn"	Difference in cost of capital; No margining by utility; minimal counterparty risk; value of proved undeveloped properties in rising market	Significant due diligence required; more administrative costs; volumetric risk; must participate in new drilling to retain % share; risk of drilling and production costs risks; environmental risks	Partner with a reputable and financially strong producer; Cap drilling and production costs in contract; invest in known field and technologies

FortisBC will need to review the cost differences between gas production options against the relative benefits and risks. Given the potential for increased demand for western Canadian gas, a physical supply may be more beneficial than a financial swap, as it provides both supply and price certainty. And, long-term ownership of production would mitigate potential counterparty risks and collateral posting requirements. The lowest cost gas production option will likely be to invest in reserves, and risks could be mitigated in part by the selection of a financially strong and experienced natural gas producer partner. For a drill and earn structure, the exploration and production risks might be mitigated by selecting an operator familiar with the extraction, processing and transportation costs. Additionally, it is possible that cost caps could be negotiated with the producer partner. Reserves ownership risk might also be mitigated by purchasing reserves in current producing fields.

Given this would be its first long-term gas hedge, the Company may want to structure an arrangement that will mitigate risks with which it is not familiar. A VPP structure would pose fewer gas production risks to FortisBC than an investment in reserves, and more closely resemble contracted supply with which it is more familiar. By having the producer retain exploration and productions risks, FortisBC could avoid production volume uncertainty and operating cost risks.

Part VIII - Long-Term Price Risk Management Framework

In its 2013/14 Annual Contracting Plans, FortisBC expressed an intent to file a new Price Risk Management Plan, exploring a range of price risk management strategies such as alternative commodity rate offerings for customers and entering into longer term fixed price purchases from suppliers.[26] Part VIII- Long-Term Price Risk Management Framework provides criteria for considering long-term price risk management.

A long-term hedge is a significant resource for the utility to commit to on behalf of customers. Since a long-term fixed price supply contract or resource has long-term rate implications, it must provide sustainable, long-term benefits to customers. From the utility's perspective, long-term hedges take time to structure and require considerable due diligence. Long-term hedges also hold more risk than short-term transactions. If the long-term price risk management transaction is a fixed price physical or financial contract, there are material credit and counterparty considerations. If it is a gas production arrangement, significant capital investment will be required. And there can be regulatory risk for the utility if the transaction goes awry, if the cost-effectiveness of the transaction is viewed in hindsight, or if regulators do not support a policy of long-term price management.

Prior to executing a long-term hedge, the utility must attain support from stakeholders and regulators. Establishing common goals for a long-term gas supply investment helps the utility confidently proceed with due diligence and efficiently close transactions that bring value to customers through reliable, stable and attractively-priced long-term supply. Agreement among the parties on what defines a valuable and prudent resource or contract is important to establish prior to proceeding with acquisitions.

Aether believes a compelling fundamental market context and market price context must be present for long-term price risk management to be a value proposition for customers. The ideal time to purchase a long-term hedge is when market prices have declined to low price levels. There is a common market theory that markets always "correct" when there are large price movements up or down. So, if new supply additions have pushed prices down, eventually new demand will be priced in and prices will move up again. The demand may come in different forms. One, if a low cost supply has fallen relative to other markets the commodity flows will change to where the low-cost supply will flow to the premium-priced markets. Two, there may

[26] FortisBC Energy, *FortisBC Energy Inc. and FortisBC Energy (Vancouver Island) Inc. 2013-14 Annual Contracting Plans*, May 1, 2013, 48.

be commodity switching; when the low cost supply drops low enough in price it is substituted for another commodity.

The substitution effect can happen in the demand sector, such as fuel switching. But it can also occur at the point of production when the producer elects to produce a higher-value product instead of continuing to produce the lower-value product. If there are barriers to entry, it may take time for these shifts in commodity flow and commodity switching, but they eventually will occur if the price dislocation is sustained over long periods of time. Last, there can be regulation or policy that forces shifts in demand for certain commodities over others. For example, clean air and water environmental regulation has reduced coal consumption in favor of alternative forms of generation.

In terms of a market price context, there are several perspectives to consider. First, the price of the long-term hedge contract or supply should be evaluated in the context of customer rates. For example, if a long-term hedge can be layered in at a price level that is attractive relative to historical customer commodity rates, then there is value in providing stable, low-priced supply into the future for customers.

Second, the price should be considered on a prospective basis. Natural gas markets are typically in contango, where forward year prices carry an annual price escalation. So, in addition to looking at the levelized price, another measure of relative value is what type of annual escalation from current year prices are built into the long-term hedge price. The resource price should also be examined next to prices of natural gas in other relevant markets. For example, if the purchase is acquired at AECO, the utility would want to find that the locational price differential (also referred to as "basis") to a major market index such as Henry Hub was reasonable in historical terms.

Last, the long-term hedge price should be compared to "replacement cost" and "marginal cost of production". The market price rarely stays above the fully embedded replacement cost. When prices are high enough for the average producer to invest capital and earn an attractive return, producers will respond to the market price signal and will commence drilling and adding production. This will lead to over-supply. At the other end of the spectrum, market price rarely trades below the marginal cost of production for a sustained period of time, for if the price falls below marginal cost, production will cease and there will be supply scarcity after surplus has been used up. Natural gas prices tend to cycle between marginal cost and replacement cost over time.

In Appendix B: Long-Term Supply and Demand Analysis, Aether has provided illustrative supply-demand factors that impact Pacific Northwest and broader North American gas prices. These are examples of fundamental market analysis and market price analysis that support long-term price risk management. These include supply trends, potential demand increases, and market price trends. A review of forecasted supply/demand fundamentals indicates a trend reversal, where increasing demand will require increasing production. Whereas prices were driven lower from 2009 to 2012 by increasing supply, there are strong indications that increasing demand will drive future supply additions. This will most likely evolve through natural gas market price increases. These factors support a strategy to pursue long-term hedging options to lock in attractively-priced long-term gas supply for customers.

A. Supply Trends

Shale gas supply has been the major gas industry news headline since supply expanded and prices fell (2009-2012). New shale extraction technology created a substantial increase in the amount of recoverable North American gas supply. The U.S. shale gas additions have more than off-set production declines in conventional North American gas production. In Canada, production in the Horn River and Montney shale plays in western Alberta and northern British Columbia has not yet produced enough gas to overcome declines in conventional producing areas. But there are considerable production opportunities in western Canada that will be available if market prices increase.

This leads to the question of production economics in the future. It is valuable to review the replacement cost of gas and the marginal cost of gas production to understand market prices relative to drilling economics. The Canadian Energy Research Institute reported that the average supply costs in 2012 were 4.79/Mcf (Canadian) for vertical gas wells and $5.71/Mcf for horizontal wells. [27] This would be approximately $4.45 USD per MMBtu and $5.31 USD per MMBtu respectively. [28] Wood McKenzie has estimated that the cost to replace shale gas reserves

[27] Canadian Energy Research Institute, *Conventional Natural Gas Supply Costs in Western Canada*, Study 136, June 2013, 2013, by Julie Dalzell, Executive Summary, ix.
[28] This conversion is based upon the closing rate of the US dollar to the Canadian dollar of $1.1055 by the Bank of Canada as of 12:00 pm EST February 10, 2014 and the American Gas Association's volumetric conversion to energy content rate of 1 cubic foot (cf) is equal to 1,027 btu.
http://www.aga.org/KC/ABOUTNATURALGAS/ADDITIONAL/Pages/HowtoMeasureNaturalGas.aspx. (accessed February 2014).

by 2020 will need to be approximately US$6.75 per MMBtu (in 2010 dollars). [29] Reviewing 2010-2012 annual reports for the larger Canadian gas producers shows declining netback margins over the past three years, and many North American gas producers have reduced natural gas drilling programs in favor of crude oil drilling. The netback margins are significantly higher for crude oil production than natural gas production.

Public concerns relating to the impact on ground-water and surface water from hydraulic fracturing operations has led to grass roots opposition to 'fracking', and in some cases, has resulted in local and state moratoriums on shale gas production. Even states that have supported shale gas production operations are beginning to implement more cautionary regulation, relating to the steps required to obtain permits and required disclosures of drilling operations. Each new level of regulation adds time and cost to producing shale gas. The response of government agencies in the form of new regulation could affect shale gas producers' production costs in the future, to where higher gas prices may be needed to off-set higher production costs.

B. Potential Demand Increases

At the same time that producers are not financially motivated to increase natural gas production given less attractive netback economics and alterative investment options, demand will be growing in future years according to US and Canadian federal agencies. The US Department of Energy's Energy Information Administration (EIA) forecasts increased gas demand in industrial, electric and transportation fuel sectors, as well as anticipated LNG exports. The largest growing gas demand sector is in the electric power generation. As a result of stringent Environmental Protection Agency (EPA) regulation[30] to limit emissions from stationary sources, there is significant pressure on generation owners to close old, inefficient coal plants. The most cost-effective replacement for energy is natural gas fired generation.

In Canada, Canadian Environmental Protection Act regulations will be going into effect in 2015 requiring all carbon fuel plants must emit no more than 420 metric tonnes of CO_2 per GWh, or they must be retired the sooner of 2019 or end of life (50 years). This regulation has the effect of forcing coal plants to emit no more than gas generation facilities. Additionally, Ontario has a plan to phase out coal generation. The Canadian National Energy Board (NEB) forecasts older

[29] *Douglas Channel Energy Project: LNG & North America Natural Gas Market Assessment (2011-2033)*, BC LNG Export License Application Schedule E- Wood Mackenzie Report, prepared for LNG Partners LLC, March 24, 2011, 15.

[30] This includes several forms of regulation: National Ambient Air Quality Standard, Mercury and Air Toxics Standard, Clean Air Mercury Rules and Clean Air Interstate Rules.

coal plants will be retired and replaced primarily by gas generation and secondarily by non-hydro renewable energy. The NEB estimates this will result in approximately 7,000 MW of new gas generation. [31]

The smallest but perhaps most interesting potential demand for North American natural gas may be as a domestic transportation fuel. In its Annual Energy Outlook 2014 Early Release, EIA forecasts domestic fuel consumption of CNG and LNG to grow, but to remain a small amount overall (1% of total demand by 2030). But, in a very different forecast, PIRA Energy Group in October 2012 projected: "Natural gas demand for large trucks and fleet vehicles could reach 14 billion cubic feet per day (Bcf/day) by 2030 – about 20 percent of today's daily gas production – according to PIRA's high-case scenario. In its lower scenario, total demand would be 7 Bcf/day."[32] It is very hard to predict the adoption rate of new technologies and the speed of commercialization. So it is not surprising that there should be wide discrepancies forecasting demand for an emerging market. The compelling factors for natural gas conversions from diesel fuel include the fuel cost differential, long-term cost stability, EPA emissions regulation, reduced greenhouse gas emissions and local air quality benefits. The large price differential between natural gas and refined oil products is considerable for marine, road and rail transportation sectors.

North American gas prices are hugely discounted to global gas prices, particularly Asian gas prices. In recent years there have been numerous projects announced for developing export capabilities to export Canadian and US natural gas. The US Department of Energy (DOE) and Federal Energy Regulatory Authority (FERC) have approved export permits for several US LNG facilities. As of November 15, 2013, the DOE had applications for 37.96 Bcf/day of LNG Export authorizations for Free Trade Association (FTA) countries and 35.11 Bcf/day of LNG Export authorizations for Non-Free Trade Association (non- FTA) countries. Of these, 33.82 Bcf/day has been approved for FTA exports and only 6.7 Bcf/day for Non-FTA exports. There are only 20 FTA countries. The major LNG importing areas such as Japan, China, Europe and India are non-FTA countries. Similarly in Canada, there are ten Canadian LNG terminals proposed (in addition to one in Oregon), of which nine are sited in British Columbia that are requesting federal approvals. The NEB has approved seven of the eleven applications.

[31] National Energy Board, *Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, November 21, 2013, 64.

[32] David Butcher, *Natural Gas Trucks Gaining Momentum*, Industry Market Trends, October 9, 2012 http://news.thomasnet.com/IMT/2012/10/09/natural-gas-trucks-gaining-momentum/ (accessed: December 2013)

There are significant barriers to entry to build and construct new export LNG facilities. Much effort must be expended to file for export applications and permits and there are large capital costs and long lead times, which may mean that new export facilities are never constructed, just as the wave of import LNG facilities projected from 2006 to 2009 did not materialize. In the case of the importing terminals, the market price dynamics changed. As the recession dampened demand and new shale production gas caused prices to fall, the import facilities were no longer needed. In this case, if gas prices rise because of other supply/demand factors, then it is possible not all the LNG export terminals permitted or forecasted to be completed may be built.

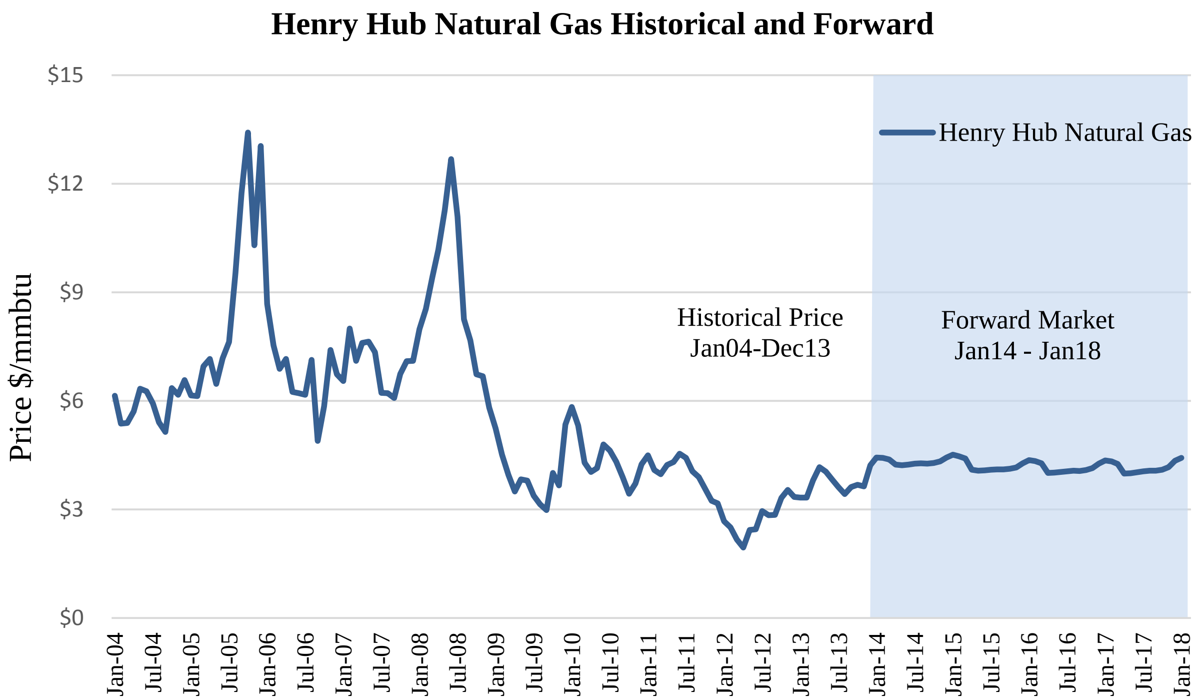
C. Market Price Analysis

To determine the value of a reference market relative to other markets, there are several key considerations. The first is the outlook for price (the price forecast) based upon a certain set of assumptions and how the forecast has changed from previous forecasts. Second, how the forecasted price compares to the forward market price (the prices that can be transacted). Third, a historical context is helpful to understand how the forward market price compares to what has been seen previously. This is especially relevant to consumer costs, as consumers have history as a context for future rates. The fourth is to compare natural gas supply costs relative to alternative energy sources. The price parameters represent the underlying fundamental supply and demand factors, as low-cost sources are substituted for more expensive alternatives and low-cost supply moves to higher value markets.

EIA's latest long-term price forecast (Annual Energy Outlook 2014 Early Release) shows a higher Henry Hub Natural Gas price trajectory for its Reference Case (base case) from its previous forecast April 2013. A side by side comparison shows an increase in natural gas exports and an increase in domestic demand in the new forecast. In April 2013, EIA published predicted gas prices would not reach $4.00 until 2020 and $6.00 per MMBtu until 2035. However, in its December 16, 2013 Annual Energy Outlook 2014 Early Release Overview natural gas price forecast, the Reference Case reaches $4.00 four years earlier by 2016 and $6.00 MMBtu five years sooner, by 2030.

The current forward Henry Hub benchmark gas market price from January 2014- January 2018 is similar to the current EIA price forecast. With respect to forward price escalation, forward market prices year over year are relatively flat in terms of annual escalation. Historical market price analysis can provide a context for forward market prices, and here, the forward price in absolute terms is relatively low compared to the last ten years of price history:

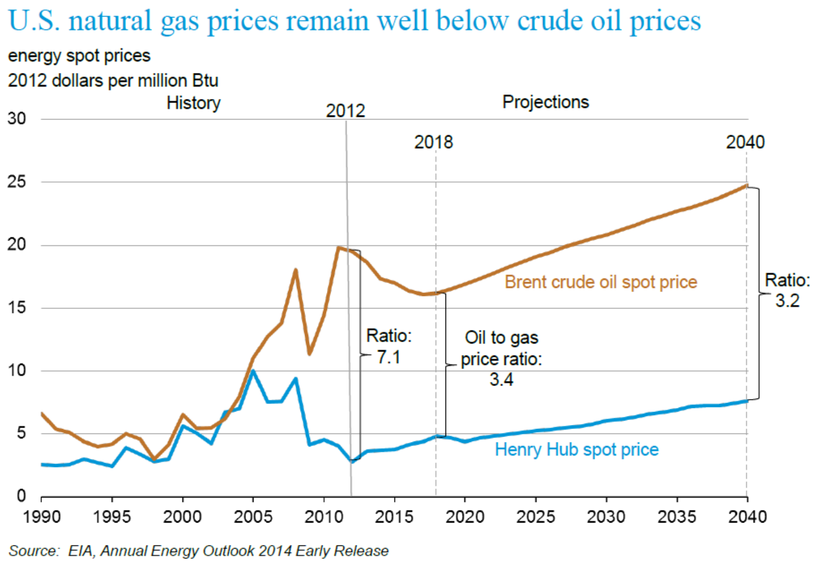
Figure 22 - Historical and Forward Market Natural Gas Prices



The above graph is the historical monthly Henry Hub Natural Gas for January 2004 through December 2013 reported by EIA. January 2014 through January 2018 prices are futures price as of 12/30/13.

In the third analysis, an alternative energy comparison, natural gas prices are compared to crude oil prices. Producers have some flexibility in what hydrocarbons to drill for: natural gas, natural gas liquids and crude oil. Comparing the North American gas prices to crude oil prices helps explain the shift from gas producers to more crude oil drilling. In its *Annual Energy Outlook 2014 Early Release*, EIA projects the current oil to gas price ratio to contract somewhat and then continue to widen:

Figure 23 - EIA: Natural Gas and Crude Oil Price Forecast



Therefore, unless price differentials between natural gas and crude oil change, the recent shift from natural gas drilling to crude oil drilling is likely to continue.

D. Summary Conclusion

Prices appeared to have hit their low in 2012 and are now beginning to increase. There has been a recent turning point where the natural gas market price has stabilized and new factors are emerging to create a different market price paradigm. In the short-term market prices are driven by weather, demand and gas inventory storage levels. But over the long-term prices are driven by long-term supply and demand factors that come from large structural changes. On the supply side, there was a long trend from 2009 to 2012 where gas production increased due to new shale gas production technology. At the same time, there was reduced demand resulting from the recession.

But going forward, the industry will likely see increasing North American demand, due to economic recovery and new regulation impacting the retirement of coal plants. This is occurring when North American gas prices are much lower on equivalent energy terms compared to global gas and crude prices. The new shale technology uncovered significant shale gas potential, but prices need to rise to levels where that production can be developed. Because additional production will be needed to meet demand, market prices will have to increase. These fundamental market drivers support long-term gas price increases in the future. Opportunities to lock in long-term prices at attractive levels should be explored to determine if FortisBC’s commodity rate reductions in recent years can be maintained into the future.

Part IX – How Other Utilities Look at Price Risk Management

In recent years, most U.S. utility commissions have continued to support utilities' gas price risk management programs, but in some cases have encouraged utilities to work with interested parties to consider alterations to hedging programs that were designed in the early 2000s to adjust for recent market events. There has also been a notable shift among some commissions to encourage utilities to explore long-term price risk management opportunities for rate stability purposes, given recent lower natural gas prices.

There are common elements to all gas utility price risk management programs. Utilities use a portfolio approach, incorporating storage and some method of fixing price (either through a fixed price contract, a call option to obtain price protection, or a collar to band prices). Utilities routinely have price risk management objectives, a risk policy and limits, and approvals to hedge from an executive risk committee or oversight board. Last, utility price risk management programs include counterparty credit risk analysis to monitor the creditworthiness of counterparties, to set limits by counterparty and to monitor potential collateral to be posted by counterparties or by the utility.

What are not standard are 1) the design of the price risk management program, 2) the percent hedged and time-frame for hedging, 3) the instruments used, or 4) the triggers that determine the hedging. Below is a sampling of utility price risk management programs, to illustrate the use of price risk management options discussed in this report. Many of the utilities provided below have similar attributes to FortisBC, such as size of operations, types of resources, regional location, number of customers, or regulatory framework.

Third-Party Survey Data: AGA and NRRI

In 2012 the American Gas Association (AGA) published an analysis relating to gas utilities' winter planning based upon a survey of sixty three local distribution companies in thirty seven states. 81% of the respondents used financial instruments to hedge a portion of their supply. Of those, 84% hedged at least seven to twelve months into the future and 54% hedged beyond twelve months.[33]

[33] AGA Energy Analysis, *LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season*, July 31, 2012.

The National Regulatory Research Institute (NRRI) also published a study in 2012, surveying thirty-five state utility commissions on long-term price risk management, defined as three years or greater[34]. The report confirmed that most commissions allow their utilities to hedge gas costs and costs are generally recovered in gas cost recovery filings. Most utilities use a combination of financial hedging tools and gas storage to manage costs for customers.

Long-term price risk management programs are usually approved on a case-by-case basis. The report notes that cost-recovery risk can be much greater for utilities entering into long-term price risk management as opposed to short-term hedging, so regulatory approval is critical for utilities before committing to long-term hedges. The NRRI survey highlighted five states that have actively encouraged their utilities to hedge through legislation or commission actions: Arizona, Colorado, Indiana, Oklahoma and Oregon.

Utility Hedging Program Models

While many Canadian utilities have suspended hedging, most US investor-owned and customer-owned utilities continue to engage in hedging. Whether the hedging is done by investor-owned utilities or by customer-owned utilities, the objective is the same- to protect customers from the potential risk associated with rising wholesale market prices. Customers are the primary beneficiary of hedging programs and the hedging costs are passed through to customers in rates. In some situations, where there are incentive mechanisms relating to energy costs, the hedging benefits the utility as well.

In many jurisdictions, utility hedging programs for investor-owned utilities are shaped by policy set by their regulatory commissions. If a commission supports long-term price stability for customers, then the utilities are more likely to engage in medium-term to long-term hedging, such as in Oregon. But in some states, the commission allows a wide variety of hedging programs among its utilities. Montana is a good example, where Montana Dakota Utilities employs no hedging and Northwestern Energy owns gas reserves. For customer-owned utilities such as municipalities, coops or public power entities, the hedging policy is set by its oversight board of commissioners or board of directors.

In Aether's experience, investor-owned utilities have more formal processes for approval of hedging program results, which may take the form of cost recovery filings, formal hearings,

[34] National Regulatory Research Institute, *Survey Responses of State Utility Commissions on Long-Term Gas Contracting and Hedging, Report No. 12-09*, Ken Costello, July 2012.

workshops and commission-directed collaboratives. Customer-owned utilities have more flexibility in their hedging program, as their oversight is generally limited to the oversight board or commission. But what is common across the entire sector is that both investor-owned and customer-owned utilities are re-examining their hedging programs and are communicating more broadly with commissions, commission staff and interested parties regarding their hedging program design and implementation.

Utility hedging programs tend to fall into three different time categories:

- Short-Term refers to managing commodity costs for the upcoming gas rate year
- Medium-Term refers to managing commodity cost for gas rate years 2-3
- Long-Term refers to the time horizon beyond gas rate year 3

Customer-owned utilities tend to have long-term hedging programs, whereas investor-owned utilities may have short-term, medium-term or long-term time horizon. Appendix C: Illustrative Utility Hedging Programs provides examples of gas and electric utilities' hedging programs in all three categories.

A. Short-Term Price Risk Management

Gas utilities typically employ gas storage to take advantage of lower-priced summer gas prices and to have additional supply to meet winter loads. Therefore, gas storage is part of all gas utilities' price risk management programs. Winter pries poses the greatest price risk exposure, so most utilities execute short-term transactions to protect against increasing winter prices. Many utilities also hedge summer gas prices.

Utilities vary in their use of physical or financial hedging. The determination is driven in part by the availability of credit-worthy physical suppliers versus financial counterparties, and at what locations the gas can be hedged. Another consideration is the utility's preparedness for new financial derivatives reporting resulting from the Dodd Frank Act and associated CFTC derivatives regulation.

The volume of hedging (including gas storage) is generally is between 50% and 80% of base case volume requirements. Utilities try to avoid hedging up to 100% percent, in the event that load is lower than forecasted. Additionally for accounting reasons, they try to avoid over-hedging. The instruments used typically are fixed price and call options.

B. Medium-Term Price Risk Management

In Aether's experience, most US utilities have medium-term price risk management programs. The volume hedged is greatest in the coming rate year, and declines over time in the future years, where the percent hedged for Year 2 is less than Year 1, and the volume hedged in Year 3 is less than the volume hedged in Year 2. The decision to hedge over multiple years is deliberate, to provide commodity cost continuity between rate years for customers.

Electric utilities tend to have somewhat more sophisticated hedging programs than gas utilities, which likely is driven by the greater complexity of their portfolios. For example, depending upon the implied market heat rate (the difference in forward market prices between fuel prices and power prices), they may need to purchase fuel to generate power or purchase power from third parties if the prices don't justify their dispatching their power plants. Additionally, electric utilities can have surplus power in some seasons, but be deficit fuel or power during other seasons.

Additionally, utilities that have incentive mechanisms around their cost of energy, or are required to assume some of the financial exposure if actual costs differ from target costs, tend to hedge greater quantities and also use more sophisticated risk management tools. These include stochastic modeling and the use of 'at risk' metrics that enable the utility to test potential risk exposure in varying scenarios.

Utilities that engage in medium-term price risk management typically develop decisional criteria for hedging, to help them determine when to hedge and how much to hedge. They may also have hedging protocols with different types of hedging purposes. With respect to hedging protocols, it is common for utilities to set a minimum hedging volume target to insure that some hedging will always be done. Some utilities have programs that allow additional hedging, given certain conditions are met. The additional hedging might be driven by historical pricing, to try to steer the utility to hedge less when certain high prices are established and more when prices are low.

Fundamental market analysis is used by many utilities to time the execution of hedges and to assess what amount to be hedged within a specified range. A utility might set aside a discretionary amount that could be hedged, based upon fundamental market analysis. Another variation would be to use a market benchmark, such as the level at which producers might shut in production volumes, as a means to determine that additional hedging would be warranted.

A third decisional tool is to measure portfolio risk exposure, as the portfolio changes and market prices change. When the potential risk exposure exceeds a certain level, then the utility would enter into new hedging transactions to keep the potential risk exposure below a targeted level. This approach recognizes that the risks inherent in the supply portfolio are different, depending upon the level of absolute prices and the amount of volatility in the market. This approach typically employs a value at risk methodology adapted for utility portfolios.

C. Long-Term Price Risk Management

Long-term risk management is driven more by opportunity and policy. Utilities typically seek approval by their oversight commissions or boards before proceeding with a long-term hedge. These are typically complex to structure, take time to negotiate, and hold material risk exposures which need to be understood and mitigated where possible Additionally, there is the potential for market prices to move up and down significantly after the transaction is negotiated, and the utility doesn't want to face disallowance risk associated with the transaction.

A number of California customer-owned electric utilities have acquired gas reserves to hedge a portion of long-term forecasted gas generation needs. Several investor-owned gas utilities have acquired long-term gas supply as well. The acquisitions of reserves by Northwestern Energy[35] and NW Natural and the ten-year producer gas contract by Public Service Colorado provide some insight into how such acquisitions have been considered, what value is seen in these supplies and what processes can support successful evaluation and review of long-term gas supply acquisitions.

Though the actions taken by these three utilities and their commissions differ somewhat, a number of common factors emerge that may prove useful in securing the benefits of long-term supply for FortisBC's customers. A number of the components that were beneficial in the approval processes for the three utilities included the following:

- **Consideration of gas reserves in the long-term resource plan** - This allows transparent analysis of the projected benefits of such acquisitions, facilitates public feedback on analysis methodologies and conclusions, and can create templates for evaluation of subsequent opportunities.
- **Development of public policy support** - In association with the resource planning process, engagement of the commission and stakeholders regarding policy issues

[35] See Appendix D for a detailed overview of Northwestern Energy's natural gas reserves acquisition program.

involving long-term acquisitions can prove beneficial when subsequent opportunities are brought forth for approval. Legislative and regulatory policy support can serve as a foundation for such purchases where future risks and benefits are ultimately uncertain. Efforts to engage policymakers prior to making acquisitions improve the productiveness of the consideration of acquisitions through the regulatory process.

- **Comparison of reserves costs to current forecasts** - While the jurisdictions all recognized reserves as providing significant risk-mitigation benefits, the direct cost of reserve acquisitions was commonly compared to then-current market gas forecasts. In these cases, the cost of reserves fell below the then-current market forecast. Using the current market forecast, a break-even price can be developed for purposes of consideration of alternatives.
- **Assessment of the risk-mitigation benefits of the proposed acquisition** - As a significant qualitative factor, commissions place emphasis on the reduced price risk profile to customers. Ensuring that the commission has a sufficient basis to make such a determination can prove to be important.
- **Mitigation of risks associated with developing reserves** - As management of reserves and operation of natural gas production are not areas in which utilities commonly have expertise, ensuring that these risks are well addressed has been a common factor in approval for commissions.
- **Evaluation of other benefits associated with the acquisition** - For instance, Northwestern's acquisition of its Battle Creek project reduced costs through it being located within Northwestern's gas transmission system. Any benefits that reduce costs or risks, in comparison to the status quo, should be evaluated and presented.
- **Evaluation of residual risks** - Remaining risks should be reviewed and approaches developed to consider them in comparison to other alternatives (including the status quo).

While all these steps may not be necessary in order to achieve approval, these factors were significant considerations in Montana, Oregon, and Colorado. These can serve as "lessons" learned, to support successful review and approval of long-term natural gas hedging.

Part X – Conclusions and Recommendations

Conclusions

Changing supply-demand fundamentals in the North American gas market over the last couple of years has resulted in a changing risk profile for FortisBC's customers. From 2009-2012, shale gas production had driven wholesale gas prices lower, and supply exceeded demand. But more recently, there has been a market price reversal, with natural gas prices rising since 2012. An emerging combination of market factors and government actions appear to be increasing gas demand in the coming years. The size and scale of that demand is uncertain, for it is difficult to estimate the size of LNG exports or the scale of increased gas generation demand resulting from coal plant retirements, but both have the potential to be large. In contrast, while there appear to be ample shale gas reserves, current gas producer economics look dim in comparison to other development options such as crude oil. Therefore, assuming forecasted natural gas demand occurs, natural gas prices will need to increase enough to attract new exploration and production investment.

As a result of shifting North American and western Canadian supply and demand factors, FortisBC's customers are vulnerable to rising natural gas prices. There are only a few third party gas marketers offering fixed rate options, and their offerings are relatively expensive compared to the current FortisBC default service rate. Recent customer research and migration data indicate not many customers are inclined to contract with marketers. In practical terms, this makes FortisBC the primary gas supplier for customers. However, the Company has no approved hedging program outside of executing Sumas basis swaps, but does have some price risk management such as gas storage to mitigate price risk from summer to winter.

Based upon the current forward price curve, there is a unique opportunity for FortisBC to lock in gas supply costs at historically low levels, with minimal yearly price escalations. The Company may have an opportunity to hedge at prices that are low by historical comparison and would prevent potentially large future commodity rate increases.

Recommendations for FortisBC's Price Risk Management Program

In developing recommendations, Aether reviewed FortisBC's previous price risk management program, as well as the program design proposed in 2011, to understand the objectives and price risk mitigation strategies. Aether considered the backdrop of the Company's supply arrangements, physical resources and rate structures, when it developed its suggestions for the price risk management program going forward. And, Aether took into account customer feedback that FortisBC gathered during two customer research initiatives in 2005 and 2012.

Based upon the conclusions above, Aether recommends FortisBC consider the following initiatives, to help protect customers from medium-term and long-term price rate shocks:

- Understand Customers' Preferences
- Develop a Customer Rate Tolerance
- Re-institute a Medium-Term Price Risk Management Program Design
- Conduct Scenario Analysis
- Consider Long-term Price Risk Management Options

A. Understand Customers' Preferences

FortisBC is relatively unique among utilities in seeking to better understand customers' preferences, and how these translate into price risk management objectives. Few utilities attempt to talk with customers about price risk management because the conversation can become complex relatively quickly. But FortisBC did an exemplary job distilling the complex topic into simple elements. In surveys and interviews with customer focus groups, the Company explored what customers were willing to absorb in rate increases and tested their reactions to different types of pricing programs.

The Company conducted a survey in 2005 and again in 2012. Aether recommends FortisBC continue every two years or so. Customers' preferences will change depending upon the external environment, and it will help inform FortisBC's Price Risk Management Program to periodically survey customers. Economic indicators, alternative energy costs, cumulative rate increases, and visible natural gas news (such as LNG exports and new gas production) may influence customers' risk tolerance. Through frequent surveys, FortisBC could track changes in risk tolerances and adapt the Price Risk Management Program accordingly.

With respect to future surveys, Aether recommends FortisBC periodically survey customers, using similar methods each time to develop a baseline and trend analysis. A number of approaches can be taken to engage customers, to investigate more fully their interest in and receptivity to alternative risk management approaches and tools and to ensure program success. These include quantitative research (conjoint analysis), focus group research and a customer advisory panel. In addition to reviewing results from customer surveys, stakeholder and BCUC staff insights will be helpful in understanding different customer groups' perspectives on rate increases and risk tolerance.

B. Develop a Customer Risk Tolerance

FortisBC's 2005 customer survey began to query customers about the maximum rate increase they could tolerate. And there was strong evidence from the 2012 customer focus group survey data that customers care about price stability. Additionally, the 2012 survey data indicated customers would like to receive some rate benefit if wholesale market prices fell. A price risk management strategy could be designed to reflect the customer risk tolerance and to incorporate customers' preferences. For example, FortisBC could hedge a portion of its portfolio to allow for some benefit if market prices fall, and the customer risk tolerance could determine what percentage of hedging is appropriate.

Both surveys provide some starting information from which to develop a new price risk management hedging program. The 2012 survey data showed that a 25% rate increase prompted up to 76% of the residential respondents to say they would change their natural gas consumption behaviour. In the earlier 2005 customer survey, customers said they could tolerate up to a $169 annual increase in their bills (which was on average 16% rate increase).[36]

These two data points can help the Company and stakeholders define a customer risk tolerance, which should be checked periodically in future surveys for potential changes. FortisBC should engage with interested parties to frame a customer rate tolerance to define the maximum amount of rate increase to be passed through to customers, and to review scenario analysis of a multiple year rate path trajectory. The tolerance could be reviewed every two years in connection to responses from future customer surveys.

To determine the right size and scale of hedging, FortisBC should test the effect of market and load events on its portfolio. For example, the portfolio scenario analysis in Part VI – Medium-Term FortisBC Portfolio Analysis indicated that with a 95% percentile extreme price movement an un-hedged portfolio would result in a 70.7% rate increase from the base case. In contrast, a 50% hedged program with fixed price instruments would only result in a 35% increase, and a 75% hedged program with fixed price instruments would result in a 17.7% increase.

[36] "Terasen Residential Customer Natural Gas Price Volatility Preferences, Qualitative Research Study February 2005", Western Opinion Research, March 14, 2005, page 4.

C. Re-institute a Medium-Term Price Risk Management Program

The question is what would be the most effective approach to offer rate stability and protect customers from rising energy bills. The Company currently offers rate structures with its EPP and CCRA deferral account that smooth rates and allow for levelized billing options, and these appear to be popular with customers. But the rate structures do not protect customers from rising costs. While FortisBC would want to maintain these rate structures, it would also need to develop solutions to manage risks to rising prices.

The 2012 customer focus group survey data indicates FortisBC's customers are not well informed about energy markets and utility services. This, taken with the low sign-up for third party marketers' offerings, may indicate that customers either do not have the interest or the expertise to self-manage their energy costs. Since customers want to avoid rate increases but would like to benefit from lower market prices, Aether is not convinced a fixed rate option (separate from FortisBC's default service) would be well-received. And a capped rate option could be very expensive, because of the cost of purchasing long-dated call options. Further, given the return of many customers to FortisBC's default service, customers may be reluctant or confused about moving to a new alternative rate structure. Customer education and outreach expenditures could be significant and FortisBC might discover it spent significant resources to implement systems to provide a fixed rate or capped rate program that only a few customers selected. Last, if FortisBC were to offer a fixed rate or capped rate structure, third party marketers may oppose such offerings.

Instead, Aether recommends FortisBC provide price protection through a price risk management plan within its default service. This would be more straightforward to manage since the Company already has the systems, infrastructure, and experience to do this. Aether recommends FortisBC's program draw upon some principles of its program prior to 2011, as well as introduce some new elements. With respect to retained principles, Aether recommends FortisBC develop a layered price risk management program. Given customers' preferences for price protection with some opportunity in case wholesale prices drop, a portion of the portfolio could be locked in over multiple years, with the largest percentage in the first year and declining percentages in future years.

A second retained program principle would be to hedge only a portion of the portfolio, shaped by customers' risk tolerance. Customers have expressed an interest in benefitting if prices fall, which is best achieved with hedging part, but not all, the portfolio. Second, while it is anticipated there would not be significant customer migration away from FortisBC, one reason to lock in costs for only part of FortisBC's commodity portfolio is so that there are no stranded hedges if some customers were to shift to third party marketers' programs in the future. FortisBC could monitor "migration" risk to confirm the risk of customers leaving the utility so it can adjust targeted hedge quantities accordingly.

In terms of how much of the portfolio to hedge, FortisBC could use customer survey information to shape its hedging guidelines. For example, in the 2005 customer survey, customers had differing responses around rate tolerance, but the average of the responses was a 16% rate increase could be tolerated. If FortisBC were to adopt that as a target, based upon the risk analysis Aether conducted of its current portfolio at current forward market prices, current implied volatility, and a 95% confidence level market price scenario, FortisBC would target hedging volumes closer to 75%, than 50%, of the total portfolio for the upcoming rate year. Aether recommends FortisBC update it hedging targets as market conditions change and as FortisBC receives different risk tolerance feedback in future customer surveys.

Aether recommends FortisBC re-institute a price risk management program that can be relevant for varying market conditions. Whenever a program is halted for regulatory review, this puts customers at risk in the event prices rise. So, it would be important to develop a program that could be adapted for different market conditions. For example, the BCUC decision to halt most of FortisBC's hedging put customers at risk. While customers benefitted from lower gas prices 2011 to 2012, they did not have much price protection when prices increased 2012 to 2013. The problem with stopping a program is that it is not easy re-start it. The process can be time-consuming, which leaves customers vulnerable to rising prices during the 6-12 months it takes for FortisBC to propose a program, obtain stakeholder support and receive approval from the commission. Therefore, it would be better for customers if FortisBC had a price risk management program that could be adapted for different kinds of market conditions.

One of the criticisms of some utilities' programs was that they were too programmatic, where the utilities applied the same strategy regardless of market conditions. FortisBC could avoid this concern by incorporating two different types of flexibility into its program. The first would be to establish price risk management percentage bands to allow some discretion for what percentage of hedging is executed between a minimum and maximum amount. The range would be determined by the customer risk tolerance. The second would be to encourage FortisBC to use different hedging instruments for different market conditions.

A price risk management program with some flexibility would allow the Company to respond to unique market events by 'flexing' the amount hedged between the minimum and maximum and the instruments used, depending upon external circumstances and changing customer preferences. Flexibility with respect to the amount hedged and the selection of instruments would enable FortisBC to adapt the price risk management program for different market conditions.

Another criticism of utility hedging programs from 2009 to 2012 was the opportunity cost. That criticism is less relevant when a customer risk tolerance is defined. As customers want some form of price protection, there will always be some percentage of hedging. Therefore, hedging program performance would focus on risk mitigation achieved, cost of mitigation, and execution cost as opposed to whether the Company should have hedged or not.

It should be noted that in today's market with prices at close to historical lows, there will be less "opportunity cost" because there is less room for forward prices to fall to levels where producers shut-in production (the theoretical floor to natural gas prices). In contrast, when prices are at much higher levels (as they were in 2009), there is more room for prices to fall and a smaller hedging percentage might be applied. In high-priced market conditions, the Company might hedge at the low range of the band, and in low priced market conditions, hedge at the high range of the band.

If stakeholders and the commission felt it was important for customers to have a 100% market-based option, then FortisBC could offer an opt-out of its default service program and provide a 100% market index rate alternative. It would be easier to manage a market-based rate for opt-out customers than to manage a fixed rate or capped rate option. And, it would not compete with the third party marketers' rate offerings.

Aether recommends that FortisBC use only a few standard price risk management instruments to keep the program mechanics relatively simple. In Part V – Medium-Term Price Risk Management Tools, Aether described several standard instruments for medium-term price risk management. Aether recommends FortisBC use rate mechanisms, storage, and short-term fixed price contracts for short-term price risk management. For medium-term price risk management, Aether recommends FortisBC use physical fixed price contracts and/or financial instruments.

With respect to which instruments to use, FortisBC could apply a fundamental market assessment and historical price analysis to ascertain whether prices were more likely to rise than fall, if prices were likely to trade within a range, or prices were more likely to fall than rise. If market prices were expected to rise, then FortisBC would likely select a fixed price instrument. If prices appeared to be range-bound, it might select a collar, and if prices appeared to be more likely to fall over time, it might use call options.

But, in addition to applying a market perspective, FortisBC would need to test the actual cost of a given hedging instrument in its portfolio, to see its effect on the baseline cost, the price exposure on the upside that would be mitigated and the opportunity that would be foregone or retained. Looking at all three drivers is important in order to understand the trade-offs. For example, a call option is attractive conceptually as an instrument to protect against price increases and to allow the utility to participate in falling markets. But it can be an expensive instrument in volatile markets for delivery far into the future, as the option premium is driven by underlying market volatility and the time value remaining. Additionally, the strike price needs to be considered relative to the risk tolerance. So, in some situations, the strike price and premium cost of a call option might seem overly expensive relative to the potential benefit if market prices fall. This is an example of where the cost of the hedge must be considered in addition to the protection and benefit it affords.

For its medium-term price risk management program, FortisBC would need to articulate a target risk tolerance as the starting point and explain how it adapted its strategy for different market conditions. In this manner, the Company would explain why it chose to hedge between the minimum and maximum range and why it selected certain instruments. Keeping contemporaneous documentation will be important so that the decisions can be seen in the context of what information was available to the Company at the time it made these determinations. In this way, the program will be more transparent to external parties and customers.

D. Conduct Scenario Analysis

Scenario analysis can also be used to test the impact of different events on a utility's gas supply portfolio to see potential rate impact. Further, scenario testing can be used to understand potential rate impact not only for the current rate year, but for the future rate years as well. Scenario analysis is also a tool to test how prospective hedges might impact the portfolio.

There are several scenario analysis methods to choose from. The first method is to conduct scenario analysis using a discrete set of defined scenarios. FortisBC could develop a matrix of scenarios that combine several factors the Company believes could occur simultaneously. For example, one scenario could be a low load scenario and low market price, while another could be a high load and high market price.

A second method would be to adapt a Value at Risk methodology to measure potential gas commodity costs risk in the overall portfolio. This can be done by developing a stochastic model that includes all elements of the Company's default service forward portfolio, including load, storage, transportation, hedges and long-term resources. A price distribution is developed for forward market prices, in order to have a full range of market prices. Typically the distribution is developed by using recent historical volatility or forward implied market volatility coupled with historical correlations between load and prices. To the degree there is variability in other elements such as load variability or production variability, they can be modeled as well.

Stochastic modeling will provide a distribution of potential outcomes for gas commodity cost, which can be translated into rate impact. The distribution narrows when a utility hedges a higher percentage of its gas supply requirements. With a layering approach, the range will be less for the current rate year, than for the upcoming rate year and the years that follow because the price risk management target range declines over time. By implementing scenario analysis, FortisBC can track the potential rate path trajectory under different market conditions and see the year over year effect on customer rates. It can also test the effect of prospective hedges and long-term supply to see the effect on customer rates.

E. Review Long-Term Price Risk Management Options

Long-term gas production acquisition is useful to consider when stakeholders and the Company are in agreement that low rates and long-term rate stability are important customer objectives. At the same time that Aether recommends FortisBC maintain an on-going medium-term price risk management program that can be adjusted for changing market conditions, Aether also recommends that long-term price risk management strategies should be pursued on an opportunistic basis when the absolute level of price is attractive, when market supply and demand factors favor rising market prices, when long-term hedging would provide long-term rate stability for customers.

Based upon recent trends, Aether believes a long-term gas production acquisition through a long-term fixed price contract, volumetric production payment or reserves should be explored. Today North American natural gas is attractively priced compared to historical prices and there appear to be many fundamental price drivers that could cause gas prices to rise in the future. Aether recommends FortisBC opportunistically explore long-term gas production options to stabilize long-term rates for customers, given low interest rates, low gas prices and uncertainty relating to future gas production and demand. Additionally, because it is a regulated entity with a strong corporate credit rating, FortisBC will likely have an attractive cost of capital relative to the producers' alternative sources of financing which will benefit customers

In Part IX- How Other Utilities Look At Risk Management and in Appendix C: Illustrative Utility Hedging Programs, Aether provided some examples of other utilities that have pursued long-term hedges. In the development of strategies to secure long-term production, it is useful to consider approaches successfully undertaken by utilities that have purchased or contracted for such long-term supply and secured approval with their state regulatory bodies. A number of utilities have learned how to acquire long-term gas supply with minimal regulatory and operational risks. There are some "lessons learned" in long-term price risk management from other jurisdictions which FortisBC can share with the BCUC and interested parties.

When determining how much long-term gas supply to hedge, the Company should use a conservative forward load forecast. Aether sees little migration risk, given most retail customers see the utility as the primary and preferred supplier. But a conservative forecast can mitigate risks of lower than expected loads in the future (perhaps because of alternative fuels or greater than expected energy efficiency). Aether also recommends the Company diversify long-term hedges over several geographic locations and with several producer partners. Given the complexity of structuring long-term gas production arrangements, spacing the execution of transactions would provide adequate time for due diligence and negotiation of terms and conditions. There are also "learning" experiences from each transaction that follow after execution of the deal. Ideally, large transactions would be spaced over 1-2 years to provide adequate time for smooth integration.

Aether recommends the Company establish long term gas hedge targets that decline over time. A higher percentage would be targeted in the early years, and the targets would decline over the time horizon. This fits the decline curve observed in gas production properties. And, it is consistent with the strategy of layering hedges in the medium-term price risk management design recommendation.

Appendix A: FortisBC Portfolio Analysis Detail

Aether conducted scenario analysis of FortisBC's portfolio, to assess the effect on the gas commodity cost (CCRA) of changes in market price and load. Please see Part VI – Medium-Term FortisBC Portfolio Analysis for a description of the analysis conducted, the chart illustrating the natural gas price distributions and the summary results.

There were three types of instruments modeled:

- Fixed price financial swap
- Call option at $.50 out of the money (the cost of the option is included in the results)
- Collar with a call option at $.50 out of the money and a put option $.35 out of the money (assumes a no-cost collar)

The load scenarios modeled were:

- Plus or minus 1% deviation from normal in annual load
- Plus or minus 3% deviation from normal in annual load and;
- Plus or minus 5% deviation from normal in winter load and 3% deviation from normal in summer load.

The prices and implied volatilities are from December 13, 2013. [37] The market price location was AECO. Aether used volatility curves provided by the Company for calendar year 2014 and extrapolated forward period volatility curves to generate the cost of out-of-the money options.

Below are the detailed scenario analysis results. The data illustrates how the deviation between the lowest price scenario and highest price scenario is greater with a low percentage hedged (25%) and smaller with a high percentage hedged (75%). It also shows that to protect against rising prices, purchasing fixed price is the lowest cost alternative. But to preserve some opportunity for lower prices in the future, a call option or a collar is preferable.

The addition of customer load impacts the level of CCRA relative to the base case for the 25%, 50% and 75% hedging scenarios. In a high price/high load scenario the commodity rate is greater than in a high price/average load scenario because the Company must acquire additional load at high prices which raises the average cost per gigajoule. In contrast, in a low price/high

[37] The results are model-simulated and may not include all transaction costs the Company could incur to execute these strategies.

load scenario, the Company can acquire additional load at low prices which brings down the average cost per gigajoule.

Un-Hedged Portfolio Results

Current Exposure $/GJ - Change in Commodity Rate from Base Case

Price Change - $/GJ	Price Scenario - Percentile					
Gas year 2014-2015	5th	20th	32nd	68th	80th	95th
Base	($1.50)	($1.31)	($0.86)	$1.13	$2.07	$2.58

Current Exposure- % Change in Commodity Rate from Base Case

Rate Exposure - % Change	Price Scenario - Percentile					
Gas year 2014-2015	5th	20th	32nd	68th	80th	95th
Base	-40.9%	-35.7%	-23.5%	31.0%	56.5%	70.7%

25% Hedged Portfolio Results, With Load Scenarios

Exposure with 25% Notional Hedged with Swap $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($1.10)	($0.96)	($0.63)	$0.83	$1.52	$1.90
	-3%	($1.11)	($0.97)	($0.64)	$0.84	$1.53	$1.92
	-1%	($1.12)	($0.98)	($0.64)	$0.85	$1.54	$1.93
	1%	($1.13)	($0.98)	($0.65)	$0.85	$1.55	$1.94
	3%	($1.13)	($0.99)	($0.65)	$0.86	$1.56	$1.96
	5%	($1.14)	($0.99)	($0.65)	$0.86	$1.57	$1.96

Exposure with 25% Notional Hedged with Swap - % Change in Commodity Rate from Base Case

Rate Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-30.2%	-26.3%	-17.3%	22.8%	41.6%	52.1%
	-3%	-30.4%	-26.5%	-17.4%	23.0%	42.0%	52.4%
	-1%	-30.6%	-26.7%	-17.6%	23.2%	42.2%	52.8%
	1%	-30.8%	-26.9%	-17.7%	23.3%	42.5%	53.2%
	3%	-31.0%	-27.1%	-17.8%	23.5%	42.8%	53.5%
	5%	-31.1%	-27.2%	-17.9%	23.5%	42.9%	53.6%

Exposure with 25% Notional Hedged with Call, $0.50 OTM, $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($1.45)	($1.26)	($0.81)	$1.02	$1.71	$2.09
	-3%	($1.45)	($1.26)	($0.81)	$1.02	$1.71	$2.10
	-1%	($1.45)	($1.26)	($0.81)	$1.02	$1.72	$2.11
	1%	($1.45)	($1.26)	($0.81)	$1.02	$1.73	$2.11
	3%	($1.45)	($1.26)	($0.81)	$1.03	$1.73	$2.12
	5%	($1.45)	($1.26)	($0.81)	$1.03	$1.73	$2.13

Exposure with 25% Notional Hedged with Call, $0.50 OTM - % Change in Commodity Rate from Base Case

Rate Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-39.6%	-34.4%	-22.1%	27.9%	46.8%	57.2%
	-3%	-39.6%	-34.4%	-22.1%	27.9%	46.8%	57.3%
	-1%	-39.6%	-34.4%	-22.2%	28.0%	47.0%	57.6%
	1%	-39.6%	-34.4%	-22.2%	28.0%	47.2%	57.9%
	3%	-39.6%	-34.5%	-22.2%	28.1%	47.4%	58.1%
	5%	-39.6%	-34.5%	-22.2%	28.1%	47.5%	58.2%

Exposure with 25% Notional Hedged with Collar, $0.50 OTM Call, $0.35 OTM Put, $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($1.19)	($1.05)	($0.73)	$0.97	$1.65	$2.03
	-3%	($1.20)	($1.06)	($0.73)	$0.97	$1.66	$2.05
	-1%	($1.21)	($1.06)	($0.73)	$0.97	$1.67	$2.06
	1%	($1.21)	($1.07)	($0.73)	$0.98	$1.68	$2.07
	3%	($1.22)	($1.07)	($0.74)	$0.98	$1.69	$2.08
	5%	($1.22)	($1.08)	($0.74)	$0.98	$1.69	$2.08

Exposure with 25% Notional Hedged with Collar, $0.50 OTM Call, $0.35 OTM Put -% Change in Commodity Rate from Base Case

Rate Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-32.7%	-28.9%	-19.8%	26.4%	45.2%	55.7%
	-3%	-32.8%	-29.0%	-19.9%	26.5%	45.5%	56.0%
	-1%	-33.0%	-29.1%	-20.0%	26.6%	45.7%	56.3%
	1%	-33.2%	-29.3%	-20.1%	26.7%	45.9%	56.6%
	3%	-33.3%	-29.4%	-20.1%	26.8%	46.1%	56.8%
	5%	-33.4%	-29.5%	-20.1%	26.8%	46.2%	56.9%

50% Hedged Portfolio Results, With Load Scenarios

Exposure with 50% Notional Hedged with Swap $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($0.71)	($0.62)	($0.41)	$0.54	$0.98	$1.22
	-3%	($0.72)	($0.63)	($0.42)	$0.55	$1.00	$1.25
	-1%	($0.74)	($0.65)	($0.43)	$0.56	$1.02	$1.28
	1%	($0.76)	($0.66)	($0.43)	$0.57	$1.04	$1.30
	3%	($0.77)	($0.67)	($0.44)	$0.58	$1.06	$1.33
	5%	($0.78)	($0.68)	($0.45)	$0.59	$1.07	$1.34

Exposure with 50% Notional Hedged with Swap - % Change in Commodity Rate from Base Case

Rate Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-19.4%	-16.9%	-11.1%	14.7%	26.8%	33.5%
	-3%	-19.8%	-17.3%	-11.4%	15.0%	27.4%	34.2%
	-1%	-20.3%	-17.7%	-11.6%	15.3%	28.0%	35.0%
	1%	-20.7%	-18.0%	-11.9%	15.7%	28.5%	35.7%
	3%	-21.1%	-18.4%	-12.1%	15.9%	29.1%	36.4%
	5%	-21.3%	-18.6%	-12.2%	16.1%	29.4%	36.7%

Exposure with 50% Notional Hedged with Call, $0.50 OTM, $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($1.40)	($1.21)	($0.76)	$0.90	$1.35	$1.60
	-3%	($1.40)	($1.21)	($0.76)	$0.91	$1.36	$1.61
	-1%	($1.40)	($1.21)	($0.76)	$0.91	$1.37	$1.63
	1%	($1.40)	($1.21)	($0.76)	$0.91	$1.39	$1.65
	3%	($1.40)	($1.21)	($0.77)	$0.92	$1.40	$1.67
	5%	($1.40)	($1.21)	($0.77)	$0.92	$1.41	$1.67

Exposure with 50% Notional Hedged with Call, $0.50 OTM - % Change in Commodity Rate from Base Case

Rate Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-38.2%	-33.0%	-20.8%	24.7%	37.0%	43.7%
	-3%	-38.2%	-33.0%	-20.8%	24.8%	37.2%	44.0%
	-1%	-38.3%	-33.1%	-20.8%	24.9%	37.5%	44.5%
	1%	-38.3%	-33.1%	-20.9%	25.0%	37.9%	45.1%
	3%	-38.4%	-33.2%	-20.9%	25.1%	38.3%	45.6%
	5%	-38.4%	-33.2%	-21.0%	25.2%	38.4%	45.8%

Exposure with 50% Notional Hedged with Collar, $0.50 OTM Call, $0.35 OTM Put, $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($0.89)	($0.80)	($0.59)	$0.80	$1.24	$1.49
	-3%	($0.91)	($0.81)	($0.60)	$0.81	$1.26	$1.51
	-1%	($0.92)	($0.82)	($0.60)	$0.81	$1.28	$1.53
	1%	($0.93)	($0.83)	($0.61)	$0.82	$1.29	$1.55
	3%	($0.94)	($0.84)	($0.61)	$0.83	$1.31	$1.57
	5%	($0.95)	($0.85)	($0.61)	$0.83	$1.31	$1.58

Exposure with 50% Notional Hedged with Collar, $0.50 OTM Call, $0.35 OTM Put -% Change in Commodity Rate from Base Case

Rate Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-24.4%	-22.0%	-16.2%	21.9%	34.0%	40.7%
	-3%	-24.8%	-22.3%	-16.3%	22.1%	34.4%	41.3%
	-1%	-25.1%	-22.5%	-16.5%	22.3%	34.9%	41.9%
	1%	-25.4%	-22.8%	-16.6%	22.4%	35.3%	42.4%
	3%	-25.7%	-23.0%	-16.7%	22.6%	35.7%	43.0%
	5%	-25.9%	-23.2%	-16.8%	22.7%	35.9%	43.3%

75% Hedged Portfolio Results, With Load Scenarios

Exposure with 75% Notional Hedged with Swap $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($0.31)	($0.28)	($0.18)	$0.24	$0.43	$0.54
	-3%	($0.34)	($0.30)	($0.19)	$0.26	$0.47	$0.59
	-1%	($0.36)	($0.32)	($0.21)	$0.27	$0.50	$0.63
	1%	($0.39)	($0.34)	($0.22)	$0.29	$0.53	$0.66
	3%	($0.41)	($0.36)	($0.23)	$0.31	$0.56	$0.70
	5%	($0.42)	($0.37)	($0.24)	$0.32	$0.58	$0.72

Exposure with 75% Notional Hedged with Swap - % Change in Commodity Rate from Base Case

Price Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-8.6%	-7.5%	-4.9%	6.5%	11.9%	14.9%
	-3%	-9.3%	-8.1%	-5.3%	7.0%	12.8%	16.0%
	-1%	-9.9%	-8.7%	-5.7%	7.5%	13.7%	17.1%
	1%	-10.5%	-9.2%	-6.0%	8.0%	14.5%	18.2%
	3%	-11.1%	-9.7%	-6.4%	8.4%	15.4%	19.2%
	5%	-11.5%	-10.0%	-6.6%	8.7%	15.8%	19.8%

Exposure with 75% Notional Hedged with Call, $0.50 OTM - % Change in Commodity Rate from Base Case

Price Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-36.8%	-31.6%	-19.4%	21.6%	27.1%	30.2%
	-3%	-36.8%	-31.7%	-19.4%	21.7%	27.5%	30.7%
	-1%	-36.9%	-31.7%	-19.5%	21.9%	28.1%	31.5%
	1%	-37.0%	-31.8%	-19.6%	22.0%	28.6%	32.3%
	3%	-37.1%	-31.9%	-19.7%	22.2%	29.2%	33.0%
	5%	-37.1%	-31.9%	-19.7%	22.3%	29.4%	33.4%

Exposure with 75% Notional Hedged with Collar, $0.50 OTM Call, $0.35 OTM Put, $/GJ - Change in Commodity Rate from Base Case

Price Exposure - $/GJ		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	($0.59)	($0.55)	($0.46)	$0.63	$0.83	$0.94
	-3%	($0.61)	($0.57)	($0.47)	$0.64	$0.86	$0.97
	-1%	($0.63)	($0.58)	($0.47)	$0.65	$0.88	$1.00
	1%	($0.64)	($0.60)	($0.48)	$0.66	$0.90	$1.04
	3%	($0.66)	($0.61)	($0.49)	$0.67	$0.93	$1.07
	5%	($0.67)	($0.62)	($0.49)	$0.68	$0.94	$1.08

Exposure with 75% Notional Hedged with Collar, $0.50 OTM Call, $0.35 OTM Put -% Change in Commodity Rate from Base Case

Price Exposure - % Change		Price Scenario - Percentile					
Gas year 2014-2015		5th	20th	32nd	68th	80th	95th
Load Change	-5%	-16.2%	-15.1%	-12.5%	17.3%	22.7%	25.7%
	-3%	-16.7%	-15.5%	-12.7%	17.6%	23.4%	26.6%
	-1%	-17.2%	-15.9%	-13.0%	17.9%	24.1%	27.5%
	1%	-17.6%	-16.3%	-13.2%	18.1%	24.7%	28.3%
	3%	-18.1%	-16.7%	-13.4%	18.4%	25.3%	29.2%
	5%	-18.4%	-16.9%	-13.5%	18.5%	25.7%	29.6%

Appendix B: Long-Term Supply and Demand Analysis

Aether gathered examples of long-term North American natural gas supply and demand factors that should be considered when evaluating opportunities to lock in long-term natural gas prices. The analysis includes a fundamental market context focusing on long-term supply and demand factors, as well as a market price analysis to evaluate forward natural gas prices in different contexts.

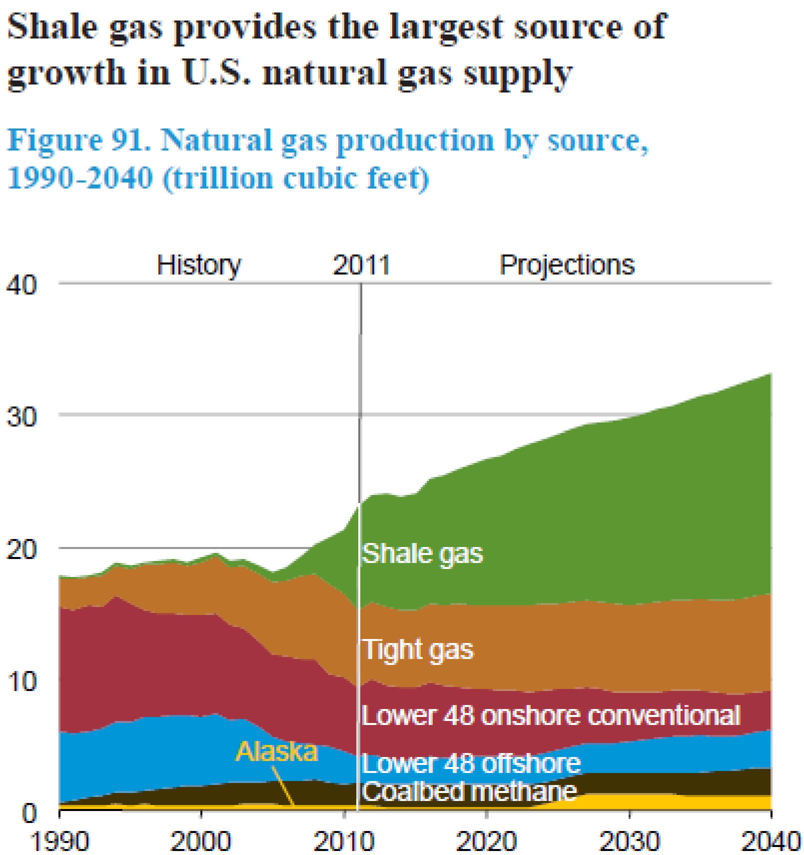
Fundamental Market Context

Energy prices move up and down, with changing supply and demand factors. When energy prices hit a low level, buyers sometimes become complacent about lower costs and assume prices will stay low. This is particularly true when supply appears to be abundant. But if prices are too low, producers will not invest in new production capacity. Also, when prices are low, new demand emerges, particularly if the energy product is low cost enough to be shipped long distance to premium-priced markets or if it is inexpensive relative to alternative energy sources. Further, there may regulatory issues that create demand for the low-cost energy source or negatively affect the cost or amount of production. These combined supply and demand factors are the crux of fundamental market analysis.

A. Monitoring Supply Trends

Shale gas technology created a substantial increase in the amount of recoverable North American gas supply. While conventional plays are in decline, new gas fracturing technology enabling producers to access vast supplies of shale gas formations more than compensate for the reduction. The graph below from Energy Information Administration (EIA) demonstrates this phenomenon. New technology that provided lower cost access to shale gas caused total US production to grow substantially from 2005 to 2013. The largest shale production areas to date have been the Marcellus Shale and Barnett Shale.

Figure 24 - EIA Shale Gas [38]



The increase in US shale gas production caused natural gas prices to fall, to where US shale gas displaced conventional US gas production. Lower prices have negatively affected Canadian production. The Horn River and Montney shales in western Alberta and northern British Columbia have tremendous production potential, but it has not been cost effective to fully develop these shale plays at the current low gas prices. At the end of 2012, marketable gas resources from Montney were estimated to be 449 trillion cubic feet (Tcf) and 78 Tcf from Horn River.[39] But current production levels are still relatively small. According to the EIA, in 2012, gross withdrawals from Horn River and Montney averaged 2.5 Bcf/d in 2012, and reached 2.8 Bcf/d by May 2013.[40]

[38] US Energy Information Administration, *Annual Energy Outlook With Projections to 2040*, April 2013, 79.
[39] Ibid, 49.
[40] EIA, *North American Leads the World in the Production of Shale Gas*, October 23 2013, http://www.eia.gov/todayinenergy/detail.cfm?id=13491 (accessed December 2014)

In 2013, the National Energy Board summarized shale gas opportunities in North America. The production potential for the Horn River and Montney shales rivals that of other major shale plays as represented by GIP (gas in place) measures. But the development has been slow. While there is significant production potential, greater demand, higher natural gas prices and additional pipeline infrastructure are needed for the British Columbia and Alberta shales to be developed fully.

Figure 25 - Comparison of Shale Gas Plays [41]

Comparison of North American Shale Gas Basins

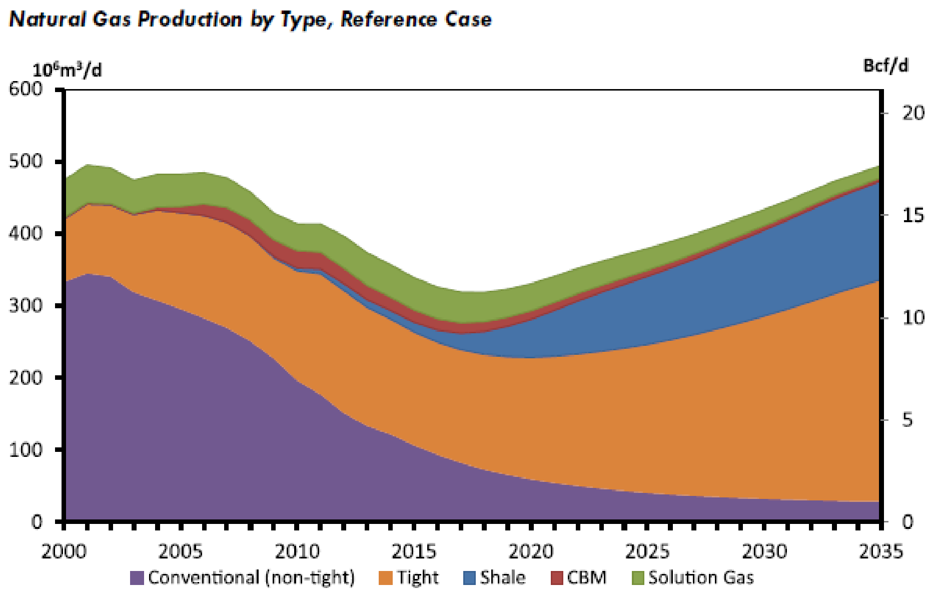
Parameter	Shale Gas Play					
	Horn River Basin	Montney (B.C. only)	Barnett	Marcellus	Haynesville	Fayetteville
Basin Area (km^2)	11 500	1 600 to 10 000	1 900	95 000	9 000	9 000
Depth (m)	1 800 to 3 000	1 000 to 3 500	2 000 to 2 600	2 500 to 3 000	3 000	350 to 2 300
Thickness (m)	50 to 350	50 to > 300	15 to 182	12 to 275	75	16 to 180
Porosity (%)	2 to 8	1 to 6	4 to 5	10	8 to 9	2 to 8
Total Organic Content (%)	1 to 8	1 to 7	4.5	3 to 12	0.5 to 4.0	4.0 to 9.8
Reservoir hydrocarbons	dry gas	wet gas, dry gas	wet gas, dry gas	wet gas, dry gas	dry gas	dry gas
Natural Fracturing	Yes	Yes	Yes	Yes	Yes	Yes
Pressure regime	Overpressured	Overpressured	Overpressured	Normal to overpressured	Overpressured	Normally pressured
Proximity to major consuming markets	Distant	Distant	Close	Very close	Close	Close
GIP (billion m^3)	12 629 (10 466 to 14 894)	2 270 to 19 800	9 263	42 492	2 0311	1 473
GIP (Tcf)	448 (372 to 529)	80 to 700	327	1 500	717	52
Marketable (billion m^3)	2 198 (1 715 to 2 714)	Uncertain	1 246	7 422	7 110	1 178
Marketable (Tcf)	78 (61 to 96)	Uncertain	44	262	251	41.6
State of development	very early	early	medium	early	medium	medium
Notes:		hybrid shale/tight-gas				

Source: U.S. data from U.S. Department of Energy *Modern Shale Gas Development in the United States: A Primer*

Canada's National Energy Board's forecast for production increases significantly in future years, when the Canadian shale gas is developed[42]. The increase in marketable production begins by 2020.

[41] National Energy Board, *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, May 2011, 17.
[42] National Energy *Board, Canada's Energy Future 2013: Energy Supply and Demand Projections to 2035*, November 21, 2013, 52.

Figure 26 - Canadian Marketable Gas Production

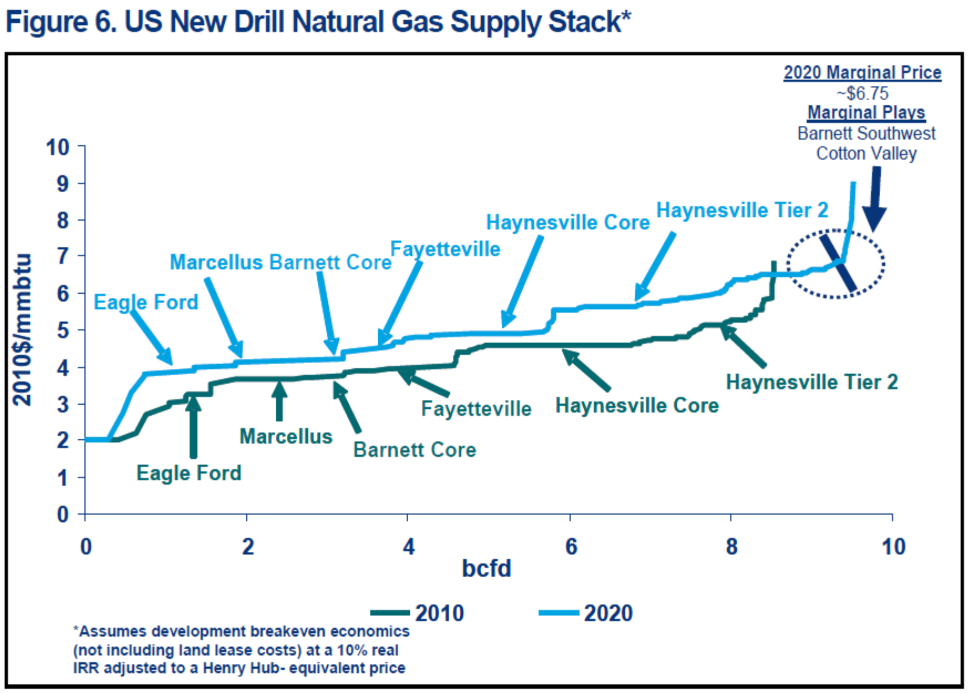


A second supply analysis is to measure the economics of production, to understand the producer's perspective. In the case of natural gas production, this translates to understanding drilling economics on a replacement cost basis and the marginal cost of production for existing properties. Replacement cost would be the cost at which a producer would invest new capital with the expectation of earning a reasonable, risk-adjusted return. Marginal cost analysis (also referred to as variable cost) examines the current margins, comparing the price at which goods are sold and the variable cost to produce. A rule of thumb is that purchasing commodities when the production cost is close to marginal cost and below replacement cost is a good risk-reward.

In 2011, Wood Mackenzie published break-even economics for shale formation gas cost replacement that indicated a $6.75 per MMBtu marginal price by 2020 for incremental shale gas investment[43]. This information was submitted in a National Energy Board (NEB) export license application.

[43] *Douglas Channel Energy Project: LNG & North America Natural Gas Market Assessment (2011-2033)*, BC LNG Export License Application Schedule E- Wood Mackenzie Report, prepared for LNG Partners LLC, March 24, 2011, 15.

Figure 27 - Excerpt from Douglas Channel LNG Export License Application



Source: Wood Mackenzie

The NEB reported in its Short-term Canadian Natural Gas Deliverability 2013-2015 report that at $3.00/MMBtu, “Canadian natural gas producers do not earn sufficient returns to attract additional equity investment.” The Canadian Energy Research Institute (CERI) reported that the average supply costs in 2012 were $4.79/Mcf (Canadian) for vertical gas wells and $5.71/Mcf for horizontal wells. The Wood Mackenzie, NEB and CERI figures help to understand the replacement cost economics for producers to invest in new drilling.

With respect to current production, the variable cost analysis is meaningful. Based upon the following operating cost and netback numbers are from a sampling of large Canadian producers’ 2012 annual report, recent market prices have not resulted in large net-back margins for producers. “Net-back” is a gross margin definition comprised of sales price minus royalties, production costs and transportation expenses. Talisman is the only entity below that had an attractive natural gas net-back, but this was augmented by higher netbacks from international gas properties. In its 2012 annual report, Talisman stated, “well-head netbacks are currently insufficient to fund drilling and development in most parts of North America.” The other Canadian producers below experienced relatively low netbacks in 2012 relative to the two prior years. A few producers additionally reported hedging benefits on a per MMBtu basis that boosted natural gas production profitability (ex: Encana $1.97/MMBtu, Cenovus $2.32/MMBtu). However, future hedging benefits may be less given the long trend of declining gas prices.

Figure 28 - Canadian Producer Netbacks

Canadian Producer	Gas Production Location	2012 Netback Per Mcf	2011 Netback Per Mcf	2010 Netback Per Mcf
Encana	**Canada**	**$0.79**	**$2.18**	**$2.60**
Talisman	**N America**	**$0.98**	**$2.51**	**$3.11**
Canadian Natural Resources	**All**	**$1.04**	**$2.50**	**$2.79**
Cenovus	**Canada**	**$1.18**	**$2.30**	**$2.88**
Husky Energy	**Western Canada**	**$1.32**	**$2.43**	**$2.21**
Suncor	**N American onshore**	**$1.88**	**$2.55**	**$2.76**

While netbacks in natural gas have been declining, the netbacks for crude oil production are very attractive. CERI reported that the average supply costs in 2012 to drill for oil in Canada were $40/bbl for horizontal wells and $64/bbl for vertical wells, which explains why only 27% of Canadian drilling rigs in 2012 were directed toward natural gas production. Using a 6:1 ratio, a gas netback of $2.00 per Mcf, would only be a $12.00 per barrel equivalent netback compared to the crude oil netback of $35-45 per barrel. The netback analysis explains the trends reported by EIA and NEB for declining Canadian production. Given the production economics between natural gas and crude oil production, there is little incentive for natural gas producers to invest in new drilling.

In the past few years, most natural gas producers have reduced capital investment in natural gas exploration and production in order to allocate more capital to crude oil and natural gas liquids production. Two of the largest US independent gas producers, Chesapeake Energy and Devon Energy, have reduced capital spending budgets on natural gas. FT.Com reported Chesapeake Energy reduced its acquisition of new drilling leases by a planned 48 per cent from $13.4 bln last year to $6.9 bln in 2013 and has shifted from gas to oil drilling. Devon Energy had reduced its capital spending from $6.2 bln in the first nine months of 2012 to $5.2 bln in the equivalent period of this year. Additionally, Devon announced in October 2013 its intention to sell its gas pipeline and processing operations. [44]

Several large Canadian producers have taken similar steps. Talisman also reported it is cutting exploration and development spending from $3.5 bln last year to about $3 bln in 2013. And, Encana reduced its capital spending 30% from $4.6 bln in 2012 to $3.5 bln for 2013 (compared to $4.6 bln in 2011). Encana is diversifying its commodity mix which is 90% natural gas to focus on liquids-rich fields. Approximately three quarters of its capital budget will be directed toward: Canada's Montney and Duvernay shales, Colorado's DJ Basin, New Mexico's San Juan Basin, and the Tuscaloosa Marine Shale in Louisiana and Mississippi.[45]

In addition, environmental concerns among the public related to clean water may increase the cost of hydraulic fracturing natural gas shale formations. Below are examples of cautionary steps taken by several US states in 2013. Each new level of regulation adds time and cost to producing from shale gas regions:

- **California**: Companies must obtain permits for fracking and the use of hydrofluoric acid and other chemicals to dissolve shale rock. California also requires notification of neighbors, public disclosure of the chemicals used, groundwater and air quality monitoring and an independent scientific study (September 2013).
- **Alaska**: Proposed regulation would require regulatory approval before fracking, notification of landowners and testing of water wells within a half-mile radius, and the full disclosure of chemicals used (September 2013).
- **New York**: There has been a ban on high volume hydraulic fracturing since 2009. The New York State Department of Environmental Conservation is completing a draft Supplemental Generic Environmental Impact Statement reviewing the health effects of high volume hydraulic fracturing. The study was to have been completed November 2013, but a ninety day extended review period was granted.
- **Illinois:** Oil and gas companies must disclose chemicals and to test water before and after drilling and the companies will be held liable for contamination (June 2013).

[44] *Chesapeake and Devon Rein In Capital Expenditure*, Ed Crooks, November 6, 2013, FT.Com, http://www.ft.com/intl/cms/s/0/a515537c-46f4-11e3-9c1b-00144feabdc0.html#axzz2omcGXnBT (accessed: December 2013)

[45] *3 Natural Gas Producers Aggressively Slashing Costs*, Arjun Sreekumar, Motley Fool, November 21, 2013, http://www.fool.com/investing/general/2013/11/21/3-gas-producers-aggressively-slashing-costs.aspx#.Ur7vCXmA0dU (accessed: December 2013)

There are also some constraints on fracking in eastern Canada. In Nova Scotia, in November 2013, the Union of Nova Scotia Municipalities passed a resolution supporting a province-wide moratorium on hydraulic fracturing. There is currently a moratorium on fracking in Nova Scotia while an independent review takes place, which should be by spring 2014. [46]

A much-anticipated report by the Environmental Protection Agency (EPA) may have wide-spread impacts on hydraulic fracturing. The study commenced in 2011, and EPA released a Progress Report in December 2012[47]. The time it is taking to complete the report foreshadows the political and commercial undertones associated with shale gas production. The 2012 Progress Report explained the draft report to be released in 2014 will include 1) analysis of existing hydraulic fracturing data, 2) scenario evaluations with computer models, 3) laboratory studies to test how well wastewater treatment processes remove contaminants from hydraulic fracturing waste water, 4) toxicity assessments of chemical used in hydraulic fracturing fluids, 5) case studies involving over 100 water samples from Colorado, North Dakota, Pennsylvania and Texas, and 6) consultation and peer review.

Another market consideration for gas production investment is interest rates. From the utility's perspective, when interest rates are low, the cost of capital to acquire gas production is less, making the investment less expensive for customers. Low interest rates means that the carrying costs from year to year are lower. Moreover, the relative cost of capital between entities is important. An A-rated utility will have a lower cost of capital than a low investment grade entity. A utility with a regulated rate of return and a high investment grade credit rating will be an attractive source of capital for an exploration and production company, which will be reflected in a lower cost for gas production for customers.

B. Potential For Demand Increases

At the same time that producers are not financially motivated to increase natural gas production given the netback economics and alterative investment options, demand will be growing in future years according to EIA. In its Annual Energy Outlook 2014 Early Release (December 2013), EIA projects steadily growing demand for US natural gas:

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[46] The Council of Canadians, *Fracking Wastewater Leaking in Nova Scotia, Calls Grow for a Ban on Fracking* , http://www.canadians.org/blog/fracking-wastewater-leaking-nova-scotia-calls-grow-ban-fracking (accessed: January 2014)

[47] Environmental Protection Agency, *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources Progress Report*, EPA 601/R-12/011, December 2012, www.epa.gov/hfstudy (accessed: December 2013)

Figure 29 - EIA: Natural Gas Supply, Disposition and Prices

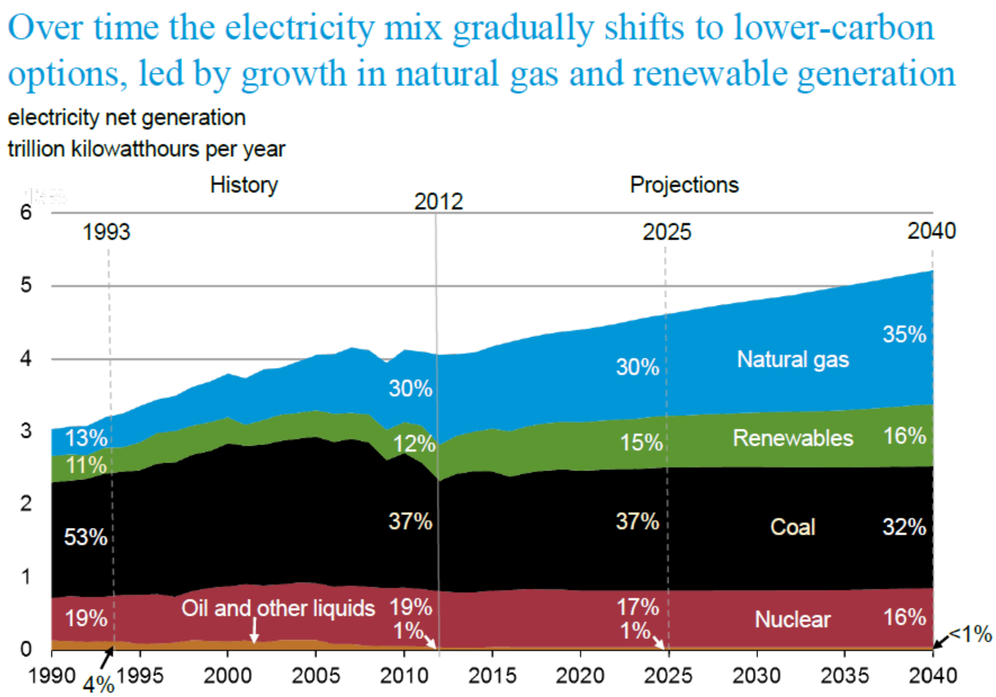
(Trillion cubic feet)

	2015	**2020**	**2025**	**2030**
Residential	4.50	4.46	4.40	4.33
Commercial	3.11	3.16	3.22	3.28
Industrial	7.70	8.09	8.41	8.52
Electric Power	8.04	8.81	9.49	10.06
Transportation	0.06	0.08	0.14	0.28
Pipeline Fuel	0.69	0.73	0.75	0.80
Lease and Plant Fuel	1.40	1.74	1.95	2.11
Total	**25.51**	**27.06**	**28.35**	**29.39**

The largest growing gas demand sector is in the electric power generation. As a result of stringent EPA regulation[48] to limit emissions from stationary sources, there is significant pressure on generation owners to close old, inefficient coal plants. The most cost-effective replacement for energy is natural gas fired generation. EIA projects significant natural gas generation additions through 2040[49]:

[48] This includes several forms of regulation: National Ambient Air Quality Standard, Mercury and Air Toxics Standard, Clean Air Mercury Rules and Clean Air Interstate Rules.
[49] U.S. Energy Information Association, *AEO2014 Early Release Overview*, December 16, 2013, http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm. (accessed: December 2013)

Figure 30 - EIA: Electricity Generation by Fuel Type



Source: *EIA, Annual Energy Outlook 2014 Early Release*

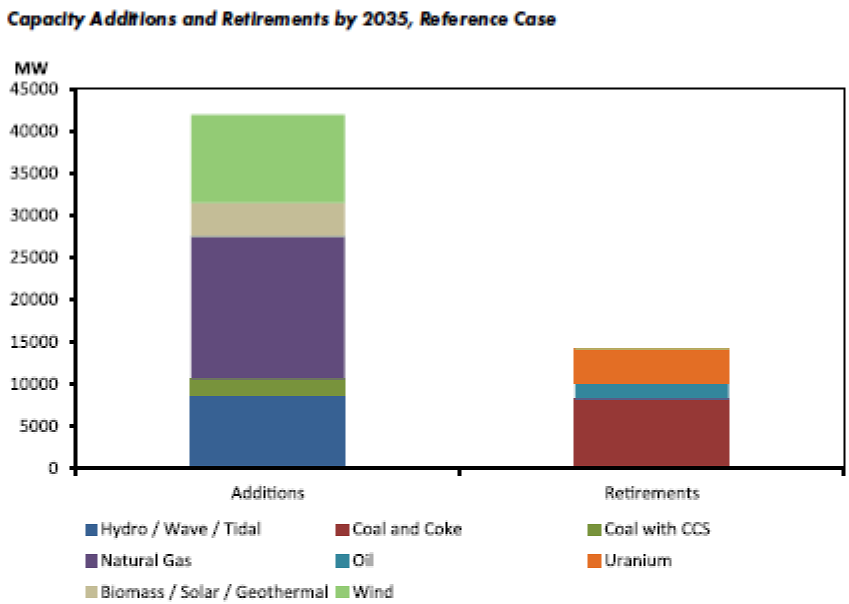
From 2008 to 2012, renewable energy had been the largest contribution to new generation capacity. This was driven by state renewable portfolio standards (RPS) and attractive U.S. federal tax credits. But more recently, the decline in natural gas prices has made renewable energy less economic. Also, in the areas where state RPS supported renewable energy additions, utilities have been able to keep pace with requirements, and there is little additional demand for renewable generation. Last, those states with large RPS have found it challenging to integrate intermittent resources such as wind and solar. The least expensive integration methods have been employed, and until battery technology drops in cost, gas generation units are required to integrate renewable energy sources.

In Canada, Canadian Environmental Protection Act regulations will be going into effect in 2015 requiring all carbon fuel plants must emit no more than 420 metric tonnes of CO2 per GWh, or they must be retired the sooner of 2019 or end of life (50 years). This regulation has the effect of forcing coal plants to emit no more than gas generation facilities. Additionally, Ontario has a plan to phase out coal generation.

The NEB forecasts approximately 9 GW of coal plant capacity will be retired between 2013 and 2035. Conventional hydro is anticipated to increase from 77 GW to 85 GW. Hydro will represent the largest generation type, but its share of the total capacity will decrease from 60% in

2012 to 56% by 2035. Gas-fired generation capacity is forecasted to increase from 20 GW to 37 GW, and will represent 40% of the total new capacity additions. Gas-generation capacity will grow from 11% of total capacity in 2012 to 21% in 2035. Non-hydro renewable resource (including wind, solar, biomass, tidal and wave) capacity will grow from 5.5% of the total capacity in 2012 to 13% by 2035. [50]

Figure 31 - NEB: Canadian Electricity Generation by Fuel Type



The smallest but perhaps most interesting potential demand for North American natural gas may be as a domestic transportation fuel. Several companies have announced intentions to shift fleet vehicle use to CNG or LNG. In its Annual Energy Outlook 2014 Early Release, EIA forecasts domestic fuel consumption of CNG and LNG to grow, but to remain a small amount overall. EIA forecasts domestic transportation demand in 2015 of .06 Tcf (.2% of total demand) to grow to .28 Tcf per year by 2030 (1% of total demand).

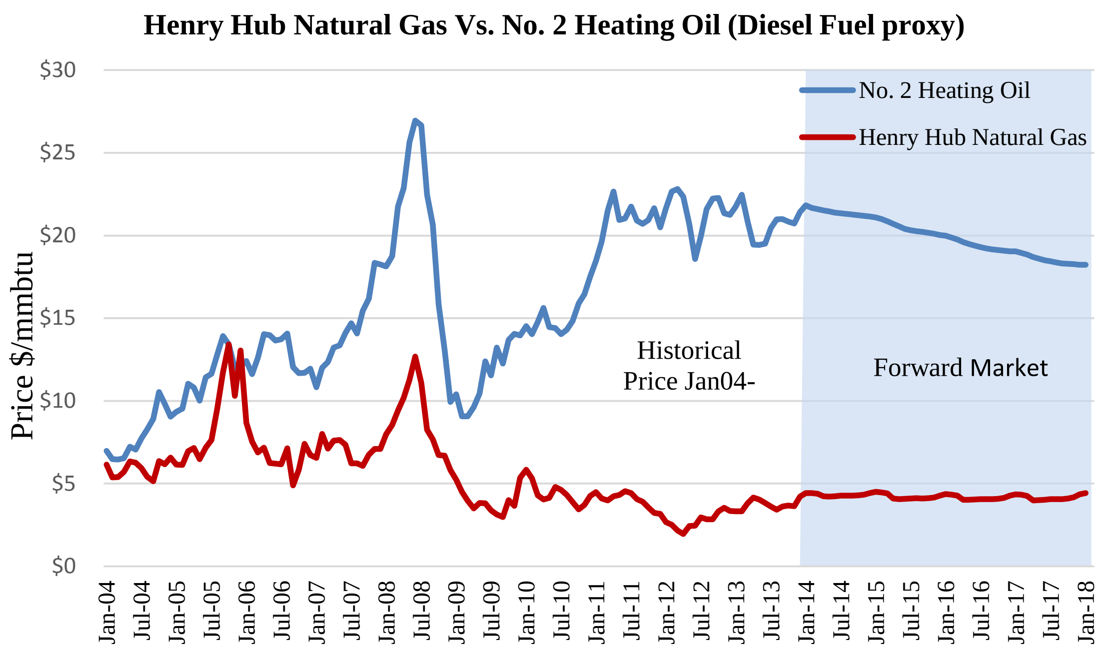
But, in a very different forecast, PIRA Energy Group in October 2012 projected: “Natural gas demand for large trucks and fleet vehicles could reach 14 billion cubic feet per day (Bcf/day) by

[50] National Energy Board, *Canada’s Energy Future 2013: Energy Supply and Demand Projections to 2035*, November 21, 2013, 64, 67-69.

2030 – about 20 percent of today's daily gas production –according to PIRA's high-case scenario. In its lower scenario, total demand would be 7 Bcf/day."[51]

It is very hard to predict the adoption rate of new technologies and the speed of commercialization. So it isn't surprising that there should be wide discrepancies forecasting demand for an emerging market. There compelling factors for natural gas conversions from diesel fuel are the fuel cost differential and EPA regulations against emissions. The large price differential between natural gas and refined oil products is considerable for marine, road and rail transportation sectors.

Figure 32 - Price Comparison of Henry Hub Natural Gas and No. 2 Heating Oil



The above graph is the historical monthly Henry Hub Natural Gas and No. 2 Heating oil (NY Harbor) for January 2004 through December 2013 reported by EIA. January 2014 through January 2018 prices are futures price as of December 30, 2013.

[51] David Butcher, *Natural Gas Trucks Gaining Momentum*, Industry Market Trends, October 9, 2012 http://news.thomasnet.com/IMT/2012/10/09/natural-gas-trucks-gaining-momentum/ (accessed: December 2013)

In the marine sector, in 2010 EPA adopted pollution emission standards for ships operating in Energy Control Areas of US waters that extend up to 200 miles off-shore the US coast. Tier 2 standards began in 2011 and more stringent Tier 3 standards begin in 2016 for reduction of emissions in "Category 3" engines, which are large propulsion engines on ships. Ships can meet 2016 Tier 3 targets by 1) burning low sulfur diesel fuel 2) installing scrubbers or 3) switching to an alternative low emissions fuel such as natural gas.

Below are recent examples of LNG applications in coastal and interior waterways:

- Totem Ocean Trailer Express (TOTE) – General Dynamics NASSCO, said that it has finalized a contract with TOTE to design the conversion of the Company's two existing Orca Class, diesel-electric trailer ships to LNG propulsion (January 2013).
- Washington State Ferries – Washington State Ferries provided a letter of intent to the US Coast Guard of its plan to convert six Issaquah class ferries to LNG. Fuel savings over the life of the vessels is estimated to be $195 million. The first one is expected to be in service in 2016 and DNV will provide the LNG propulsion system (November 2013).
- BC Ferries – BC Ferries has confirmed it plans to commission three new intermediate class ferries with LNG for in service 2016 in British Columbia. It estimates saving 50% on fuel costs (December 2013).
- Société de Traversieres du Quebec – The ferry service will be using three LNG-fueled ferries beginning in 2015. Wärtsilä will be providing the LNG propulsion system.
- Interlake Steam Company – Interlake will be the first Great Lakes shipping Company to convert a ship to LNG in 2015. Shell Oil is building a small liquefaction facility capable of producing 250,000 ton/year in Sarnia, Ontario to provide fuel to Interlake and others (May 2013)
- Shell LNG, U.S. Gulf Coast operations – Shell is also planning to build a 250,000 ton per annum liquefaction plant in Geismar, Louisiana to serve the lower Mississippi River and the Gulf Intracoastal Waterway. Shell has leased three ships that can use either diesel or LNG to support its Gulf of Mexico operations, and will supply them from Geismar. Shell also announced a supply contract with Edison Chouest that will barge LNG to re-fuel customers' ships at the firm's Port Fourchon facilities (March 2013).
- Waller Marine, Baton Rouge, LA - Waller Marine announced plans for a facility at the Port of Greater Baton Rouge that will cost around $200 million and provide approximately 450,000 gallons per day (March 2013).

In the road transportation sector, in 2011 EPA and the National Highway Traffic Safety Administration under the direction of the Department of Transportation, developed regulation to reduce greenhouse gas emissions from, and increase fuel efficiency use in, heavy duty trucks[52] for model years 2014-2018 ("Heavy Duty National Program"). It applies to all trucks weighing over 8500 pounds. Emissions are expected to drop 17% for diesel trucks and 12% for gasoline trucks by 2018.

There are three LNG infrastructure models emerging to serve heavy duty truck fleets. The first is a "return to base" model where trucks return to a single re-fueling point that is a centrally located liquefaction facility. In Colorado, Noble Energy is building a 100,000 gallon/day facility in Weld County, CO to fuel drilling rigs and heavy duty trucks. Another model is to develop regional infrastructure for a major anchor client to support regional trucking. An example of this is the network that United Parcel Service (UPS) is building. The company plans to have thirteen LNG re-fueling stations operational by 2014 to support truck delivery in Florida, Illinois, Indiana, Mississippi, Missouri, Ohio, Pennsylvania and Texas for 1,000 LNG vehicles, displacing more than 24 million gallons of diesel fuel annually.

A third model is where a retailer builds out a network and customers come to the network. In 2012, Clean Energy announced its 150 LNG truck-stops **"**America's Natural Gas Highway (ANGH)", with many facilities in partnership with Pilot Truckstops. The highway segments planned for early opening include: San Diego-Los Angeles-Riverside-Las Vegas; the Texas Triangle (Houston- San Antonio- Dallas/ Ft. Worth); Los Angeles-Dallas; Houston-Chicago; Chicago-Atlanta; and a network of stations along major highways in the mid-west region to serve the heavy trucking traffic in the area. Shell Oil and TravelCenters of America also are building out a network of 100 nationwide truck stops.

In Canada, ENN announced plans for three truck-stop LNG fueling centers in Alberta, to serve Western Canadian truck routes. ENN announced intentions to build two liquefaction plants in partnership with Ferus Natural Gas Fuels with 100,000 gallons/day capacity in British Columbia and Alberta. Construction is expected to start in 2014, with a commercial in-service date in 2016. ENN also announced five re-fueling stations, three in British Columbia and two in Ontario.

Compressed natural gas (CNG) has been making in-roads with smaller duty trucks, taxi fleets and bus lines. Questar Fueling has signed an agreement to build, own and operate a compressed natural gas (CNG) fueling facility in Houston, Texas, that will serve up to 200 natural gas-powered trucks operated by Swift Transportation and Central Freight Lines. In October 2013,

[52] Classes 2B through 8.

AMP Americas signed a deal with Dairy Farmers of America and Select Milk Producers, to convert their fleets to CNG. AMP- Trillium will build seven CNG fueling stations in Texas, for a fleet that travels more than 13.2 million miles per year. The CNG will be used in 40 Class-8 Kenworth and Peterbilt CNG sleeper trucks, a number that will double over the course of the agreement. And CNG is being used in many locations for buses and waste-haulers.

In the rail sector, EPA finalized regulation to reduce diesel locomotives' emissions by as much as 90% for new manufactured engines built in 2015 and later. EPA standards also apply for existing locomotives when they are re-manufactured. As a result several railroads are looking at using natural gas as a transportation fuel. According to EIA, in 2012, railroad diesel consumption was 5% of total US diesel retail sales. Burlington National Santa Fe Railroad (BNSF) announced it would test LNG with one of its locomotive (March 2013) and Canadian National Railroad is running a pilot with two of its locomotives. In 2012 it retrofitted two locomotives to run on a mixture of 90% LNG and 10% diesel and in June 2013, it announced plans to acquire four LNG tenders from Westport to avoid having to retro-fit diesel tanks on its locomotives. By bringing the LNG by tender on the train, the railroad will have less fueling stops and be able to run longer distances between re-fueling. Locomotive manufacturers Electro-Motive Diesel (Caterpillar) and GE have announced their own gas fueled locomotive models. More recently, in November 2013, CSX Corporation and GE Transportation announced plans to field test LNG technology in its locomotives.

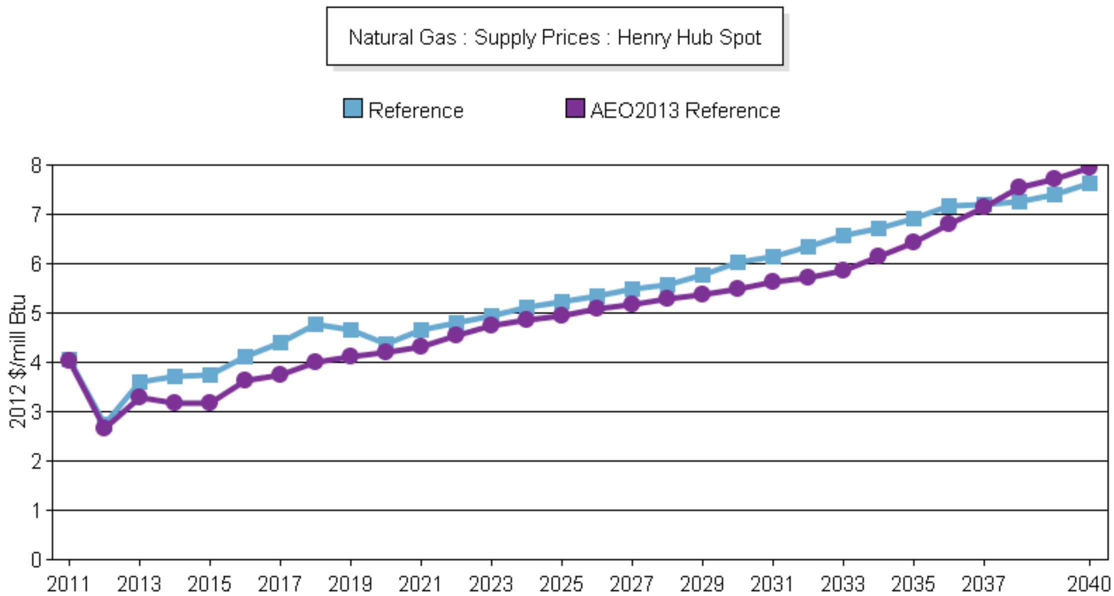
Market Price Analysis

To determine relative value of a reference market relative to other markets, there are several key considerations. The first is the outlook for price (the price forecast) based upon a certain set of assumptions. The price forecast can be compared to the forward market price for comparison purposes. Second, a historical context is helpful to understand how the forward price compares to what has been seen previously. This is especially relevant to consumer costs, as consumers have history as a context for future rates. The third is to compare natural gas supply costs relative to alternative energy sources. And the last is to track the commodity flow of natural gas from discounted-price markets to premium-priced markets. The price parameters represent the underlying fundamental supply and demand factors, as low-cost sources are substituted for more expensive alternatives and low-cost supply moves to higher value markets.

A. EIA Price Forecast

EIA's latest long-term price forecast from its Annual Energy Outlook 2014 Early Release shows a higher Henry Hub Natural Gas price trajectory for its December 2013 forecast (light blue line, "Reference") from its previous forecast April 2013 (purple line, "AEO 2013 Reference").

Figure 33 - EIA: Henry Hub Spot Price Forecast (Early 2014 Release Reference vs. April 2013)



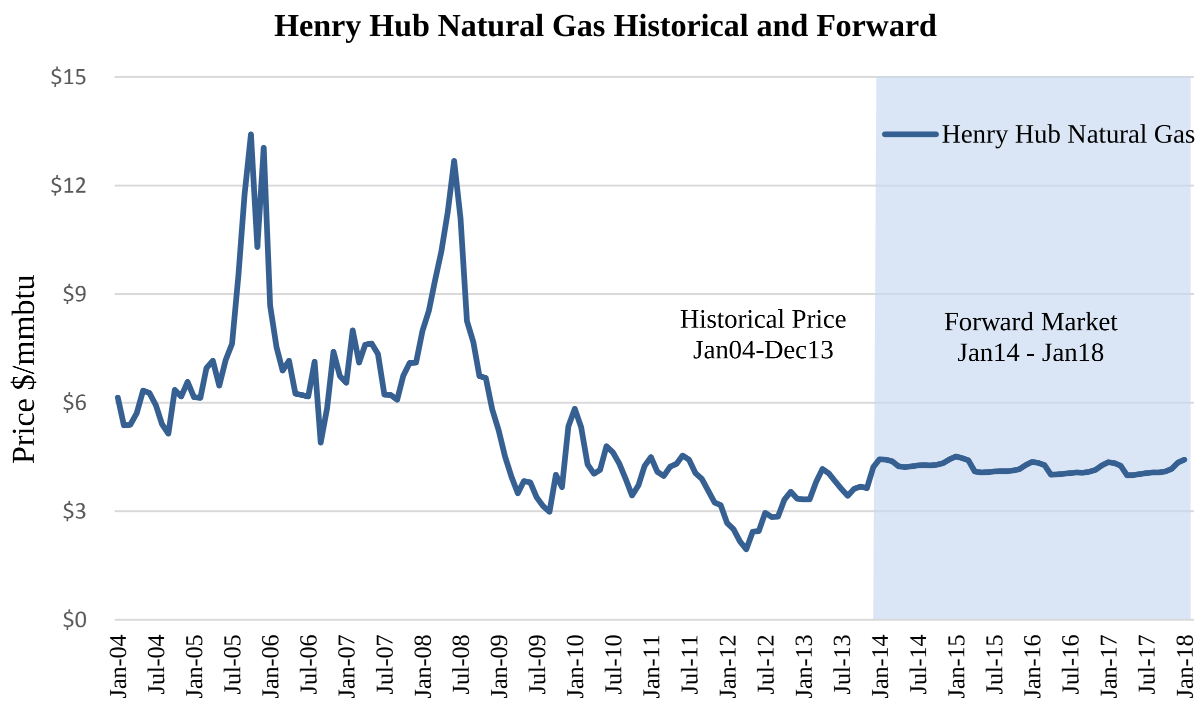
Independent Statistics & Analysis
U.S. Energy Information Administration

A side by side comparison shows an increase in natural gas exports and an increase in domestic demand in the new forecast. To meet these, North American production must increase, which is likely why the price forecast has been increased. In April 2013, EIA published the following gas price forecast, in which the base case (Reference Price) predicted gas prices would not reach $4.00 until 2020 and $6.00 per MMBtu until 2035. However, in its December 16, 2013 Annual Energy Outlook 2014 Early Release Overview natural gas price forecast, the Reference Case reaches $4.00 four years earlier by 2016 and $6.00 MMBtu five years sooner, by 2030.

B. Historical Market Price Analysis

Historical market price analysis can provide a context for forward market prices. The current forward Henry Hub benchmark gas market price from January 2014- January 2018 is similar to the current EIA price forecast. Prices year over year are relatively flat in terms of annual escalation. More importantly, the forward price in absolute terms is relatively low compared to the last ten years of price history:

Figure 34 - Historical and Forward Natural Gas Market Prices



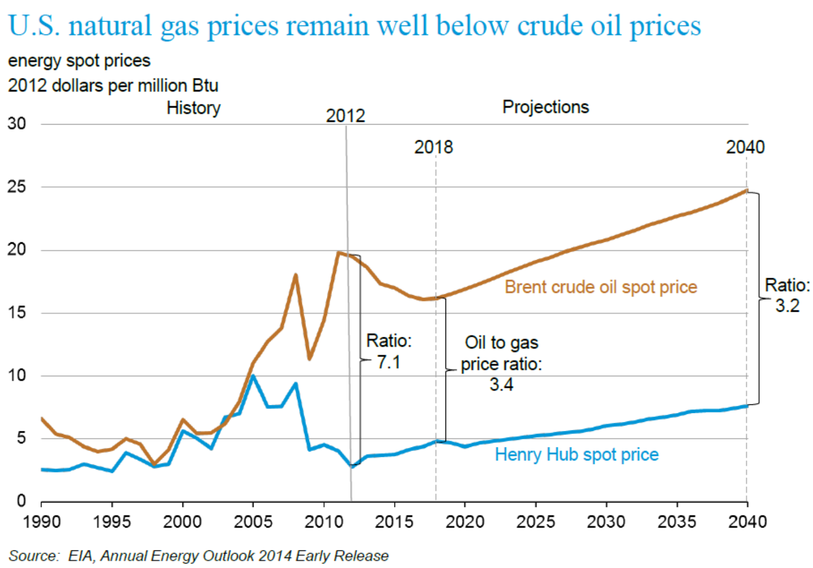
The above graph is the historical monthly Henry Hub Natural Gas for January 2004 through December 2013 reported by EIA. January 2014 through January 2018 prices are futures price as of 12/30/13.

C. Alternative Energy Comparison

In the third analysis, an alternative energy comparison, natural gas prices are compared to crude oil prices. Producers have some flexibility in what hydrocarbons to drill for: natural gas, natural gas liquids and crude oil. Comparing the North American gas prices to crude oil prices helps explain the shift from gas producers to more crude oil drilling. In recent years, the US and Canada together produced more crude oil than any Middle East producer including Saudi Arabia.

Because of global crude oil supply-demand fundamentals (declines in other nations' production and growing global demand), North American crude oil has continued to maintain a large premium to North American natural gas. The 2012 netback differential between natural gas and crude oil is reflected into the future through forward market prices, indicating there is little incentive for producers to invest in natural gas exploration and production, while very attractive margins are available in crude oil production. Therefore, unless price differentials between natural gas and crude oil change, recent drilling and production trends are likely to continue. In its *Annual Energy Outlook 2014 Early Release*, EIA projects the current oil to gas price ratio to contract somewhat and then continue to widen:

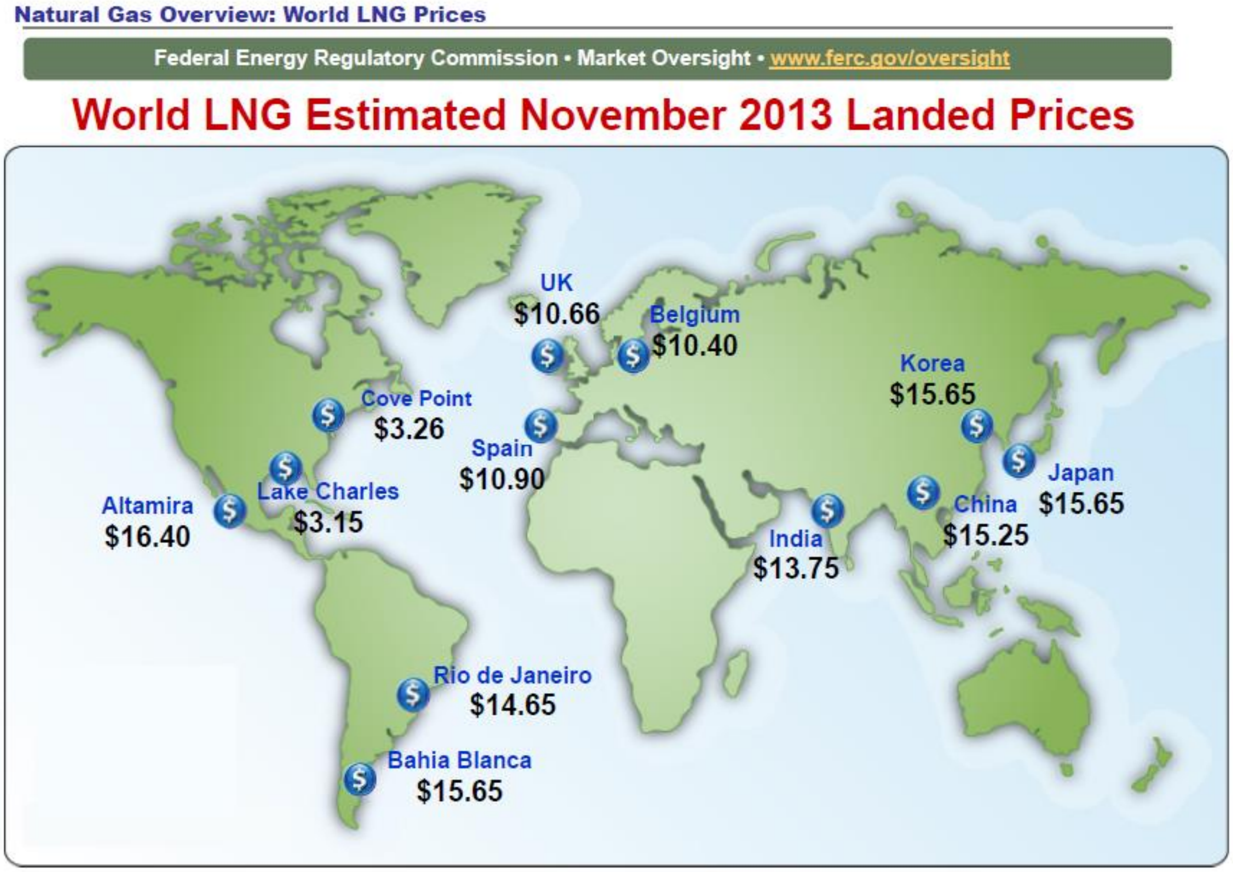
Figure 35 - EIA: Natural Gas and Crude Oil Price Forecast



D. Commodity Flow Analysis

A commodity flow analysis identifies premium and discount markets to determine the logical flow of commodity movements. For example, the map below provides a sense for how North American natural gas prices compare to global natural gas prices. The map below shows the large discount between North American gas prices and global natural gas prices:

Figure 36 - World LNG Prices [53]



According to the report "U.S. Liquefied Natural Gas Exports: A Primer on the Process and the Debate",[54] Cheniere Energy has estimated a cost of $3.07 per million cubic feet, or Mcf, for liquefaction, and a cost of $1.02 per Mcf to ship LNG to Europe and $3.07 per Mcf to ship it to Asia. A report "The Future of Natural Gas" estimates a cost of $0.70 per Mcf for re-gasification[55]. Every operator's economics will be different, but it is clear that the current

[53] Federal Energy Regulatory Commission, *Market Oversight*. Source: Waterborne Energy, Inc., October 2013. www.ferc.gov/oversight (accessed: December 2013)
[54] Center For American Progress, *U.S. Liquefied Natural Gas Exports: A Primer on the Process and the Debate*, Gwynne Taraska, November 5, 2013, http://www.americanprogress.org/issues/green/report/2013/11/05/78610/u-s-liquefied-natural-gas-exports/ (accessed: December 2013)
[55] *The Future of Natural Gas, An Interdisciplinary MIT Study*, June 2011, 25.

market price differentials observed in global spot markets exceed the additional cost of $4.81-$6.86 to convert North American supply to delivered re-gasified gas on a delivered basis.

There have been several studies undertaken to estimate the impact to US natural gas prices if exports were to begin. Cheniere LNG commissioned Deloitte to conduct an analysis, who estimated an $.84/MMBtu narrowing in the price differential between US and European wholesale market gas prices ($.15 increase in average US city gate prices and $.69 decrease in European prices) if the US were to begin exporting 6 Bcf/day to Europe 2016-2030. The most recent Energy Information Administration's (EIA) Long-Term Energy Outlook published December 13, 2013 estimates average US total supply to be 26.5 Tcf in 2016 and rising to 29.6 Tcf by 2030[56]. 6 Bcf/day of LNG exports would represent 8.2 - 7.4% of total supply over that period (EIA forecasts LNG exports approaching 6 Bcf/day by 2026).

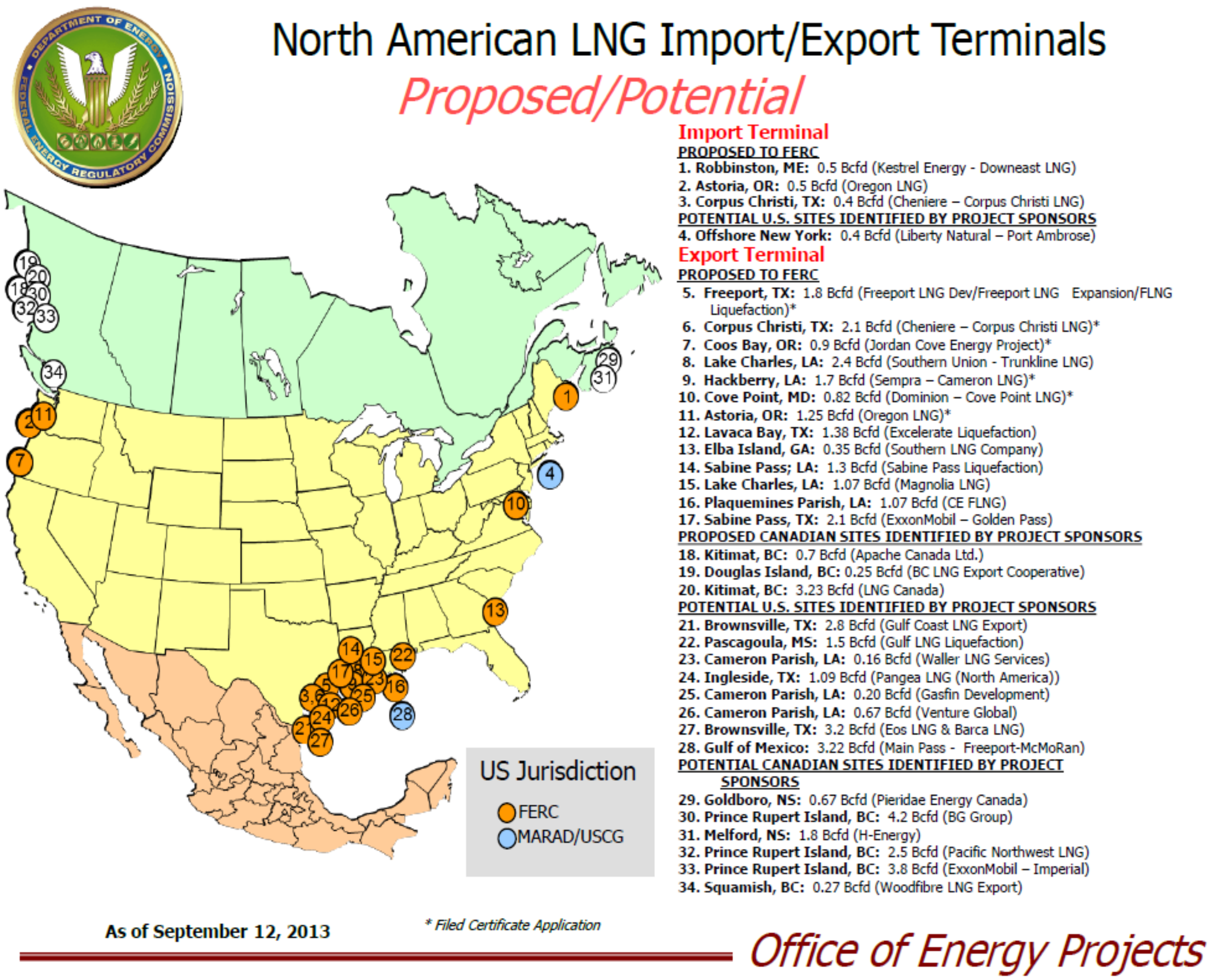
The US Department of Energy asked NERA Economic Consulting (NERA) to conduct a similar analysis as a pre-condition to approval of export LNG authorizations. In 2012, NERA submitted its study that concluded there was a positive economic impact associated with US LNG exports. In terms of price effect, NERA estimated that the initial price impact in the first five years would be $.00 to $.33 per Mcf ($2010) and this would grow to $.22 to $1.11 per Mcf ($2010) after five years. NERA additionally said that US natural gas prices would not rise to global prices, although they did say that US production would increase to meet export demand: "The natural gas sector could experience an increase in production by 0.4 Tcf to 1.5 Tcf by 2020 and 0.3 Tcf to 2.6 Tcf by 2035 to support LNG exports"[57]. Bentek Energy LLC also developed several forecasts for global LNG and potential for US exports in September 2012. Their perspective was that the global demand (measured in gasification capacity) is significantly greater than LNG supply (measured in liquefaction capacity) and that North American export capacity is needed.

In recent years there have been numerous projects announced for developing export capabilities to export Canadian and US natural gas. The US Department of Energy (DOE) and Federal Energy Regulatory Authority (FERC) have approved export permits for several US LNG facilities. The map and table below summarize the proposed projects in the US and Canada. It is important to note the majority of Canadian projects are in British Columbia.

[56] Deloitte Center for Energy Solutions and Deloitte MarketPoint LLC, *Exploiting the American Renaissance: Global Impact of LNG Exports from the United States*, 2013, 2.

[57] NERA Economic Consulting, *Macroeconomic Impacts of LNG Exports from the United States*, December 3, 2012, 77.

Figure 37 - Proposed North American Export Terminals (DOE)



As of November 15, 2013, the DOE had applications for 37.96 Bcf/day of LNG Export authorizations for Free Trade Association (FTA) countries and 35.11 Bcf/day of LNG Export authorizations for Non-Free Trade Association (non- FTA) countries. Of these, 33.82 Bcf/day has been approved for FTA exports and only 6.7 Bcf/day for Non-FTA exports. There are only 20 FTA countries. The major LNG importing areas such as Japan, China, Europe and India are non-FTA countries.

At this time there are ten Canadian LNG terminals proposed (in addition to one in Oregon), of which nine are sited in British Columbia. The NEB has approved seven of the eleven applications:

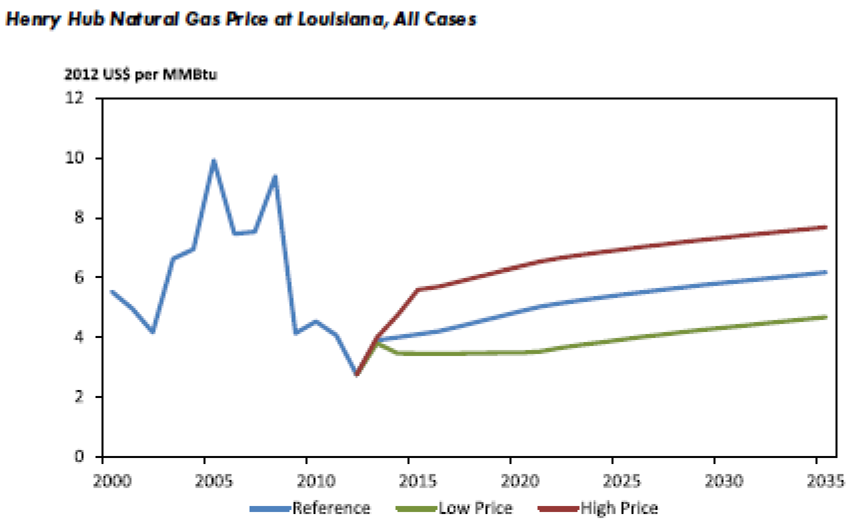
Figure 38 - Export Authorizations Before the NEB

Company	Application Status	Term Length	Project Sponsors and Capacity (tonnes/annum)
KM LNG Operating General Partnership (BC)	Approved	20 years	Apache Canada and Chevron Canada 5 million to start, potential to expand to 10 million
BC LNG Export Cooperative LLC (BC)	Approved	20 years	Privately held partnership and Haisla Nation 0.7 million
LNG Canada Development Inc. (BC)	Approved	25 years	Shell Canada, KOGAS, Mitsubishi and Petrochina 12 million, potential to expand to 24 million
Pacific NorthWest LNG Ltd. (BC)	Approved	25 years	Petronas and Japex 6 million
WCC LNG Ltd. (BC)	Approved	25 years	Imperial Oil and ExxonMobil Canada 10-15 million, potential to expand to 30 million
Prince Rupert LNG Exports Limited (BC)	Approved	25 years	BG Group Up to 21 million (3 trains)
Woodfibre LNG Export Pte. Ltd. (BC)	Approved	25 years	Pacific Oil & Gas Limited 2.1 million
Jordan Cove LNG L.P. (OR)	Under review	25 years	Veresen Inc. 6 million, potential to expand to 9 million
Triton LNG Limited Partnership (BC)	Under review	25 years	AltaGas Ltd. and Idemitsu Canada 2.3 million
Pieridae Energy Ltd. (NS)	Under review	20 years	Pieridae Energy Canada Ltd 5 million, potential to expand to 10 million
Aurora Liquefied Natural Gas Ltd. (BC)	Under review	25 years	CNOOC (through Nexen), Inpex Corp and JGC Corp 12 million

British Columbia Premier Christy Clarke is a strong supporter of LNG exports; her government is planning to apply tax revenues from LNG exports to the BC Prosperity Fund in order to retire some provincial debt. In order to tap into significant shale gas potential in Northern British Columbia and western Alberta in the Horn River and Montney Shales, export LNG prices will need to be higher than current domestic prices. LNG terminal investors and the provincial government are trying to sell Canadian natural gas at global gas price indices (based upon crude oil formula pricing currently used in Asian LNG markets). Higher prices would be required to make the LNG projects feasible and to attract additional production.

The National Energy's Board's reference case projects total exportable surplus at 5 billion cubic feet (Bcf) per day by 2035, but this doubles to 10 Bcf per day under its high price scenario by 2035. Below are the reference price, low price and high price cases assumed for the analysis, using the Henry Hub LA benchmark price.[58]

Figure 39 - Benchmark Natural Gas Prices from NEB's "Canada's Energy Future 2013"



There are significant barriers to entry to build and construct new export LNG facilities. Much effort must be expended to file for export applications and permits and there are large capital costs and long lead times, which may mean that new export facilities are never constructed, just as the wave of import LNG facilities projected from 2006 to 2009 did not materialize. In the case of the importing terminals, the market price dynamics changed. As the recession dampened demand and new shale production gas caused prices to fall, the import facilities were no longer needed. In this case, if gas prices rise because of other supply/demand factors, then not all the LNG export terminals may be built.

[58] Ibid, 55.

Appendix C: Illustrative Utility Hedging Programs

Below are examples of short-term, medium-term and long-term utility hedging programs.

Short-Term Price Risk Management (One Year)

Delmarva Power (Gas) – Delaware

The Delaware Public Service Commission requires Delmarva Power to hedge on a non-discretionary basis 50% of the projected monthly gas requirements which is defined as load plus gas for storage injections. The hedge costs are recovered in the commodity charge of the Gas Cost Rate (GCR). The utility is limited to hedging to twelve months forward on a ratable basis ($1/12^{th}$ each moth).[59] For the gas year November 2013 through October 2014, the company's filing indicated it had hedged 21% of the total GCR Requirements Purchases and had storage inventory to make a total short-term hedged position of 44% of total requirements.

New Jersey Natural Gas (Gas) – New Jersey

At the time of filing its annual Basic Gas Supply Service (BGSS) filing for the 2013-2014 winter season, New Jersey Natural Gas had hedged 62% of the projected winter period with fixed price positions.[60] The utility's goal is to hedge 75% winter by November 1 and 25% for the coming twelve month period following winter (April- March), using financial derivatives. As part of its BGSS, New Jersey Natural Gas has a series of incentive programs relating to off-system sales, capacity release, financial risk management and storage where 80-85% (depending upon the program) of the utility gross margin generated by these program is shared with firm customers and 15-20% is retained by New Jersey Natural.[61] The state of New Jersey has retail customer choice for all gas customers ("New Jersey Natural Gas Energy Choice Program").

Northern Utilities of Maine/Unitil (Gas) – Maine

In April 2013, the State of Maine Public Utilities Commission approved changes to Northern Utilities, Inc.'s (Northern) hedging program. The company had a portfolio approach to use physical hedges and financial hedges to fix prices for 70% of November through April needs (composed of 50% storage and 20% financial hedges) and 40% of the May through October

[59] Delaware Public Service Commission, *In the Matter of the Application of Delmarva Power & Light Company for the Application of Modifications to Its Gas Cost Rates,* PSC Docket No. 08-266F, Order 7658, October 6, 2009.
[60] State of New Jersey Board of Public utilities, *New Jersey Natural Gas Company Annual Review and Revision of is Basic Gas Supply Service (BGSS) and Conservation Incentive Program (CIP) Factors for F/Y 2014*. Direct Testimony and Exhibits of Jayana S. Shah, Director- Gas Supply NJNG Energy Services, May 29, 2013, 8.
[61] New Jersey Natural Resources, *2013 Annual Report*, 40.

needs. One change to the program was to shift from fixed price hedges to out-of-the-money call options to hedge against price spikes above the prevailing forward market price. The second change is the same volume target will be maintained for winter, but summer hedging will be discontinued. Northern will purchase option contracts during the spring and summer months for the subsequent winter season that starts eighteen months after the purchases being made. Northern will commence the new hedging program for winter of 2014-2015. Northern will calculate an option budget, and the strike prices will be determined by the market premiums for the options. The Commission acknowledged in its order that "Using options means that Northern and Its customers are accepting the risk of prices increasing up to the strike price but would preserve potential benefits of price decreases."[62]

Medium-Term Price Risk Management (One to Three Years)

Cascade Natural Gas (Gas) – Oregon, Washington (the information below relates to Washington)
According to documents filed with the Washington Utilities and Transportation Commission, Cascade Natural Gas (Cascade) had an active financial hedging program from 2004-2007: 77% of its portfolio was hedged with financial instruments in the gas year 2004-2005, 63% for 2005-2006, and 40% 2006-2007. Subsequently, the Company has reduced financial hedging down to 0%. It continues to use storage for seasonal hedging and has shifted to using physical fixed price contracts for hedging additional gas price exposure. [63] The company has a multiple-year physical supply portfolio, and for the 2012-2013 rate year the company hedged 40% of total gas requirements using physical fixed price contracts and used physical storage capacity at Jackson Prairie and Plymouth LNG. The company's risk policy allows for hedging out to three years in time.

Consumers Energy (Gas) – Michigan
Consumers Energy hedges 2-3 years forward in time to manage gas costs for customers, using two hedging strategies of programmatic and discretionary hedging. The first is a "tier" strategy to ensure a certain amount of gas is purchased at fixed prices before the start of the rate year and at certain intervals within the rate year. Tier purchases are made quarterly on a programmatic basis. The tied fixed price targets by quarter are as follows:

[62] State of Maine Public Service Commission, *Northern Utilities Inc. d/b/a Unitil Request for Approval of Changes to Hedging Program*, Docket No. 2012-00448, April 25, 2013, 2.
[63] Washington Utilities and Transportation Commission, *Report of Commission Staff Regarding The Natural Gas Hedging Policies and Practices of: Avista Corporation, Docket UG 1215-1, Puget Sound Energy Inc., Docket UG-121569, Cascade Natural Gas Corporate, Dockets UG-121592 and UG-121623, and Northwest Natural Gas Company, Docket UG-121434*, March 1, 2003, 9.

Rate Year Period	1st Q	2nd Q	3rd Q	4th Q
April-March	15-20%	25-30%	-	-
Nov-March	-	-	35-40%	50%

The tier strategy calls for 15-20% of all purchase requirements for the rate year to be under fixed price contracts by the December 1 prior to the start of the rate year and 35-40% of the winter requirements by July 1 of the same rate year. [64]

The second strategy, the "quartile" program, enables the company to enter into opportunistic fixed price contracts one or more years into the future. For this approach the company compares NYMEX forward prices to a median of historical values. The purchase targets vary depending upon how far below the medium price the forward prices fall by quartile and when the delivery period is. In its 2011-2012 rate year, it had hedged 63% of total year volumes with fixed price purchases.

In a 2012 order, the Michigan Public Service Commission allowed cost recovery under Consumers Energy's two-tiered hedging program but it put the company on notice that hedging strategies that worked well in the early 2000s might not be the right strategies for current markets: "As the ALJ [Administrative Law Judge] and the other parties point out, purchasing guidelines cannot be used in vacuum; they must be combined with a fundamental market analysis of the market *at the time of purchasing*. Thus, if there are current or expected market factors that would conflict with the guidelines, these factors must be taken into account and the Company must use discretion, up to and including deviating from the guidelines, if actual circumstances warrant such action. If this departure turns out badly for customers it will certainly be challenged in the reconciliation, but such challenges will fail if the Company provides clear evidence for why it set the guidelines aside. Thus, the guidelines so protect the utility from a certain degree of hindsight analysis, otherwise hedging strategies would be impossible to fairly implement." [65] The state of Michigan has retail customer choice for all gas customers ("Gas Customer Choice").

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[64] Michigan Public Service Commission, *In the Matter of the Application of Consumers Energy Company For the Approval of a Gas Cost Recovery Plan and Authorization of Gas Cost Recovery Factors for the 12-Month period of April 2011 Through March 2012*, Case No. U-16485, Notice of Proposal For Decision, September 12, 2011, 21-22.

[65] Michigan Public Service Commission, *In the Matter of the Application of Consumers Energy Company For the Approval of a Gas Cost Recovery Plan and Authorization of Gas Cost Recovery Factors for the 12-Month period of April 2011 Through March 2012*, Case No. U-16485, March 8, 2012, 18.

Intermountain Gas (Gas) – Idaho

Intermountain Gas' hedging strategies include the use of financial and physical delivery contracts. The Company has shifted recently to more short-term contracts, lowering its winter hedging ratios from 90% to 69% in 2011.[66] For the 2013 rate year, storage is estimated to meet 38% of projected requirements.[67] The Company's risk policy allows for hedging out to three years forward in time.

Manitoba Hydro (Centra Gas Manitoba Inc.) – Manitoba

Manitoba Hydro through its subsidiary Centra Gas Manitoba Inc. ("Centra") offers Fixed Rate Service (FRS) options to natural gas consumers. These options provide residential and commercial customers the ability to lock in their Primary Gas (commodity) rate for 1, 3 or 5-year terms. The Manitoba Public Utilities Board (PUB) approved these programs in Order No. 156/08 in December 2008. The PUB found that "a competitive marketplace for natural gas had not developed in a meaningful way for small volume customers" emphasizing, "Fulfilling the objectives – increase choice while providing meaningful service offerings and economic benefits – are the Board's goals." The PUB noted that while marketers have offered a number of different products, they had only competed directly on five-year fixed price offerings to residential and commercial customers and noted that, "The Board would prefer different market participants competing directly with the same contract term." In order to increase competition and provide more options to these customers, the PUB supported Centra's proposal to gradually enter the market beginning with 1, 3 and 5-year products. The PUB "views Centra's entry into the market as providing a yardstick or benchmark for marketer prices." [68]

Customers can choose to buy Primary Gas from Centra or from a natural gas marketer. The utility describes its provision of additional options for customers as, "The Fixed Rate Service is being offered to improve customer choice and meet varying customer preferences for fixed-rate Primary Gas fixed rate products. The more choice available, the better the chance that customers can find the products which meet their specific individual needs. We have no preference whether you purchase your Primary Gas on a quarterly or fixed-rate service." [69]

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[66] Idaho Public Service Commission, *In The Matter of the Applications of Intermountain Gas Company For Authority to Change its Prices (2011 Purchased Gas Cost Adjustment),* Case No. INT-G-11-01, Order No. 32372, 4.

[67] *Intermountain Gas Company Integrated Resource Plan 2013-2017*, Exhibits 1-5, Case # INT-G-13-03, February 2013, 636.

[68] Manitoba Public Utilities Board, *In the Matter of Centra Gas Manitoba Inc. Fixed-Rate Primary Gas Services Application*, Order No. 156/08, 2-3.

[69] Centra Gas Manitoba Inc., http://www.hydro.mb.ca/customer_services/purchasing_natural_gas/fixed_rate_faq.shtml (accessed December 2013)

Centra sets defined enrollment periods for the program, limiting availability of the offerings in order to manage risks associated with entering into fixed-rate contracts. Customer options are exclusive, that is, customers are served either through marketers, under the utility's quarterly market service or the utility's fixed priced options – no combinations of these options are allowed. If customers take no action following the end of a fixed-priced service term, that customer's service returns to quarterly market pricing.

Puget Sound Energy (Gas) – Washington

Puget Sound Energy (Puget) uses a two-tier program for hedging in the gas utility. The first tier is a programmatic, dollar cost averaging program where hedges are layered in over time, and a higher percentage is hedged for the coming gas year and less in the forward years. The utility also has a discretionary hedging element (called a "Cash Cost Component") where a price trigger to purchase additional supply is calculated at the production costs[70] for a basket of natural gas producers. From the period of 2004 to 2012, Puget used financial and fixed price hedges in its gas portfolio, for a total of 50% to 66% of the portfolio.

Puget Sound Energy (Electric) – Washington

Puget Sound Energy (Puget) is subject to a Power Cost Adjustment (PCA) mechanism related to its power costs. The PCA sharing bands for excess power costs or power cost savings between Puget and customers is below. This mechanism poses financial earnings risks to the utility, so that the utility hedges not only for customers but also for shareholders:

Annual Power Cost Variability	Customer %	Company %
+/- $20 million	0%	100%
$20-$40 million	50%	50%
$40- $120 million	90%	10%
+ $120 million	95%	5%

The Company uses a programmatic hedging program ("Programmatically Managed Hedge") to ratably hedge forward gas and power costs in its electric portfolio.[71] In order to determine which risk exposures are greatest and how much to hedge within the range of allowed volumes, Puget employs a "Margin-at-Risk" metric. The Company uses a stochastic model that incorporates

[70] The production costs are derived from SEC filings of publicly traded natural gas exploration and production companies.

[71] Washington Utilities and Transportation Commission, *2011 Puget Sound Energy General Rate Case*, Second Exhibit (Confidential) to the Pre-filed Direct Testimony of David Mills on Behalf of Puget Sound Energy, Inc., redacted version, June 11, 2011.

hydro variability, gas and power price variability, load variability and unit availability scenarios, to test hedging strategies' effect on the portfolio risks.

Long-Term Price Risk Management (Beyond Three Years)

Avista Utilities (Gas) – Oregon, Idaho, Washington (the information below relates to Washington)

Avista Utilities' (Avista) hedging extends out 4 years into the future. For the rate year 2013-2014, Avista hedged 40% of estimated total load requirements with fixed price instruments. Storage capacity at Jackson Prairie represents 21% of annual load requirements and 37% of December to March load requirements.[72] Avista employs a combined programmatic and discretionary hedging approach. The programmatic hedging ("periodic" is the term used) is done through setting windows for hedging at specific time periods, and setting a floor and ceiling price for each open window. The Company may decide not to hedge during an open window, depending upon market conditions. Additionally, Avista's gas utility engages in discretionary hedging ("opportunistic" is the term used) when prices fall below specified price targets.

Northwest Natural Gas (Gas) – Oregon, Washington (the information below relates to Oregon)

As a part of its PGA mechanism in Oregon, prior to the commencement of the rate year, Northwest Natural Gas (NW Natural) selects either a sharing mechanism of 10% company /90% customers or 20% company/ 80% customers of the differential (high or lower) between filed PGA costs and actual gas costs. NW Natural hedges approximately 75% of the annual gas requirements, employing both financial and physical hedges. For the rate year 2012-2013, the composition was 47% financial swaps and option contracts and 28% physical gas supplies including storage.

In 2011, NW Natural entered into agreements with Encana Oil and Gas (USA) Inc. to acquire a working interest in proved producing properties and proved undeveloped properties in the Jonah Field in Wyoming. The agreement called for NNW Natural to invest $250 million over five years, as the investment funded new drilling costs in exchange for an ownership interest in wells. The gas production will grow over time and then decline, and is estimated to meet 8-10% of the company's gas requirements for the next ten years, and total savings was estimated at over $50 million over thirty years relative to forward prices at that time. Encana is the operator and is also

[72] Washington Utilities and Transportation Commission, *Avista Utilities 2013 PGA Filing*, September 13, 2013, 2.

the majority owner in the field. The utility stakeholders and the commission staff agreed to the acquisition in a stipulation agreement which the Oregon Public Utility Commission approved.

Northwestern Energy (Gas) – Montana, Nebraska, and South Dakota (the information below relates to Montana)

Northwestern Energy (Northwestern) has developed a significant natural gas reserves portfolio, seeing such resource acquisitions as significantly reducing supply cost variability to its gas customers. This strategy was developed and articulated in its 2008 and 2010 Gas Procurement Plans and has been supported by the Montana Public Service Commission (Montana PSC). Northwestern has entered into three major properties as the major leaseholder in Montana at Battle Creek ($12.4 M for 8.4 Bcf of proven producing reserves plus gathering system), Bear Paw North ($19.5 M for 13.4 Bcf of proven producing reserves plus gathering system) and Bear Paw South ($70.2 M for 64.6 Bcf of proven producing reserves plus gathering system and acquisition of Havre Pipeline Company). Northwestern expects the Bear Paw South purchase should lock in gas supply at $4.10 per dekatherm for the next 20 years. [73]

The Battle Creek acquisition was deemed prudent in a 2012 Montana PSC proceeding and included in rate base. A filing relating to Bear Paw North is expected to be made soon with the Montana PSC for prudence determination and inclusion in rate base. The Bear Paw South transaction closed in December 2013 and its costs will be included in Gas Tracker with a subsequent filing expected with Montana PSC for prudence determination and inclusion in rate base. Northwestern is targeting to acquire reserves for 50% of its gas supply requirements for gas customers. With the acquisition of Bear Paw South, a 37% level has been reached and opportunities to close the remaining 13% unfilled position are being examined.[74]

PacifiCorp (Electric) – California, Idaho, Oregon, Utah, Washington, Wyoming (the information below relates to Oregon, Utah and Wyoming)

In four of the states in which it operates, PacifiCorp has mechanisms where the company shares with customers any deviations in power costs[75]. This mechanism poses financial earnings risks to the utility, so that the utility hedges not only for customers but also for shareholders. The sharing percentages between customers and the company for positive or negative deviations in actual power costs relative to forecasted power costs are as follows:

[73] See Appendix B for a detailed summary of Northwestern's gas reserves acquisitions.
[74] Montana Public Service Commission, *MPSC Comments on NWE's 2010 Gas Procurement Plan in Docket No. N2010.12.111*, Order 7210b, Docket No. D2012.3.25 and Northwestern Energy's presentation at EEI's 2013 Financial Conference.
[75] PacifiCorp, *2012 10K Report*, 19.

State	Customer %	Company %
Idaho	90%	10%
Oregon	90%	10%
Utah	70%	30%
Wyoming	70%	30%

PacifiCorp hedges natural gas because of its ownership in natural gas generation. Following hedging collaborative workshops with stakeholders in Oregon, Utah and Wyoming between 2011 and 2012, PacifiCorp has revised the standard hedging program time horizon from five to three years. The utility uses volumetric guidelines as well as value at risk target (VaR) and time to expiration value at risk target (TEVaR) to serve as hedging guidelines. The hedging program includes a variety of instruments- financial swaps, physical fixed-price and options- to hedge gradually over time in a dollar cost averaging approach. The percent hedged is highest for the 1st year, and lower for the following second and third twelve-month periods.[76] The Time to Expiry Value at Risk (TEVaR) models the combined gas and power positions, and runs simulations using a stochastic model to quantify potential risk exposure for customers, associated with the open positions (i.e., un-hedged positions). The primary difference between the TEVaR and a conventional VaR is that the TEVaR calculation assumes all positions are held until delivery as opposed to a VaR calculation that typically assumes positions are held for a period of days.

Beyond its standard hedging program, PacifiCorp is also exploring longer-term hedging alternatives. In May 2012, PacifiCorp solicited offers for long-term gas hedges. The most attractive offers to the Company were a 4-6 year fixed price contract, a 4-6 year collar and a 7-10 year fixed price contract. When the preferred offers were refreshed, the prices offered were not attractive and PacifiCorp indicated it would not contract at that time. Since then, the company has indicated it may conduct more RFPs for similar products in the future. [77] In October 2013, the company convened a workshop to discuss valuation criteria with stakeholders for future RFPs.[78] The company provided an overview of long-term gas supply hedging alternatives under review. It summarized evaluation criteria relating to instrument type, price valuation criteria, and counterparty credit exposure analysis.

[76] PacifiCorp *2013 Integrated Resource Plan Volume 1*, April 30, 2013, 274-281.
[77] Ibid, 53.
[78] PacifiCorp, *2012 Natural Gas Request for Proposals Workshop*, October 29, 2013.

Portland General Electric (Electric) – Oregon

Like Puget and PacifiCorp, Portland General Electric (Portland General) is subject to a power cost mechanism called a "Power Cost Adjustment Mechanism (PCAM)". A baseline power cost is set annually where positive and negative variations in power costs are shared between the company and customers. The PCAM utilizes an asymmetrical dead-band range within which Portland General absorbs cost variances, with a 90/10 sharing of such variances between customers and the company outside of the dead-band. The dead-band range is fixed at $15 million below, to $30 million above the baseline power costs. This mechanism poses financial earnings risks to the utility, so that the utility hedges not only for customers but also for shareholders. The sharing percentages between customers and the company for positive or negative deviations in actual power costs relative to forecasted power costs are as follows:

Annual Power Cost Variability	Customer %	Company %
-$15 / + $30 million	0%	100%
Outside dead bank	90%	10%

The company uses instruments such as physical fixed price, financial swaps and options for hedging. In its 2009 10K Annual Report, Portland General described a value at risk methodology to measure potential risk exposure in its power portfolio. The portfolio included estimated retail load, and all financial and physical power and gas purchases and sales. The company ran a value at risk exposure analysis for the upcoming 24 months of its portfolio, to measure the impact of a one-day holding period at a 95% confidence level.

In its 2013 Draft Integrated Resource Plan, Portland General described a five year strategy to programmatically layer in natural gas hedges to hedge natural gas–fired power generation fuel risk. The hedged percentage of the portfolio is largest in the near-term, and the percent hedged declines over time in the forward portfolio. In the front two years, Portland General buys and sells into the commodities markets for power and gas depending upon the economic dispatch of its generation based upon forward price curves. For the period of two to five years, Portland General combines physical index supply transactions with financial derivatives to hedge fuel costs. Historically, the utility used fixed price swaps, but in response to new Dodd Frank CFTC regulation, the company is transitioning to using futures. Portland General has explored options for longer-term hedging beyond five years but expresses concern about the lack of market liquidity and the potential for posting large amounts of collateral. The company says it will explore options to invest in gas reserves as an alternative: "However, given the historically low gas prices, our Action Plan calls for further exploration of the potential merits of long-term gas supply (including storage and reserves)." [79]

Public Service Colorado (parent: Xcel Energy, Electric) – Colorado

In April 2010, the Colorado legislation signed into law the "Colorado Clean Air- Clean Jobs Act (House Bill 10-1365), This legislation required state reduction in emissions of nitrogen oxide by 2017 and utilities were allowed to propose emission controls, generation fuel re-fueling or coal plant retirements. The legislation required investor-owned utilities to consider natural gas generation as a compliance option. Recognizing that long-term gas contracts may be required to protect electricity customers, the legislation required the Colorado Public Utility Commission to pre-approve long-term contracts and prohibited the reversal of approvals of long-term gas contracts by future commissions.

The majority of Public Service Colorado's (PSCo) natural gas supply for electric generation is supplied under a long-term agreement with Anadarko Energy Services Company. The remainder is priced according to market indices and PSCo hedges a portion of that remaining risk through financial instruments. The Company secured the Anadarko contract under an RFP process for long-term natural gas supplied from Colorado production as fuel for gas-fired generation. On December 9, 2010, in Docket 10M-245E, the Colorado Public Utilities Commission approved this contract which has a ten-year term commencing in 2012, a delivery quantity that ramps to 50,000 MMBtu/day and includes a fixed price with an annual escalation. The Commission's prudence finding was made in consideration of the Company's estimated $100 million NPV savings, reduced volatility and corresponding overall emissions reductions through "increased natural gas burn" for generation over alternate scenarios. In its order the Commission encouraged the Company to investigate additional long-term contracts for generation.

Southern California Public Power Authority, LADWP and Turlock Irrigation District (Electric) – California

In 2005 a consortium of public power utilities in California together acquired gas reserves. The group paid $300 million to Anschutz Pinedale Corp. for 38 oil and gas wells on 1,800 acres of the Pinedale Anticline for an expected 112 billion cubic feet of natural gas production over the life of the field. Southern California Public Power Authority (SCPPA)[80] led the acquisition on behalf of Los Angeles Department of Water & Power (LADWP) who acquired 74.5% of the total purchase, Turlock Irrigation District (Turlock), and the cities of Anaheim, Burbank, Colton,

[79] Portland General Electric Company, *Draft Integrated Resource Plan 2013*, November 22, 2013, 88-90.

[80] Southern California Public Power Authority is a Joint Powers Authority (formed under the Joint Powers Act of the California Legislature in 1980) and has 12 public power agency members.

Glendale and Pasadena. In its 2005-2006 Annual Report, SCPPA noted “This purchase, along with similar future purchases, will provide a secure source of gas for the participants, and hedge against volatile prices in the market.”[81]

In a 2012 audit report, Crowe Horwath reviewed LADWP’s hedging program, which consisted of a five year rolling hedging program and a long-term reserves strategy.[82] The auditor noted for fiscal year 2011, LADWP’s had hedged 45.69% of the total estimated gas fuel requirements, where 7.12% was met with natural gas reserves, 4.11 % with physical power, 13.65% physical gas hedges and 20.81% financial hedges. LADWP suspended its hedging program from September 2009 to June 2011, while a new Energy Cost Adjustment Factor (ECAF) was being developed.

In 2006, SCPPA members (Anaheim, Burbank, Colton, and Pasadena)[83] and Turlock purchased additional reserves in the Barnett Shale in Texas of approximately 67 Bcf. SCPPA’s Executive Director noted, "For economic, environmental and reliability reasons, SCPPA members have invested heavily in base-load natural gas generation. This acquisition will help ensure the firm delivery of natural gas at stable prices – in a highly volatile natural gas market. This initiative will further enhance the participants’ ability to achieve its goal of maintaining stable retail electric rates for their customers." SCPPA also stressed the importance of their partnership with Devon as operator, “As the largest and most active E&P company in the field, SCPPA’s participants will benefit from their extensive experience, technical workforce and service-vendor relationships.”[84] In its 2012 Annual Report, SCPPA stated an intention to secure “similar future purchases.” The properties were acquired from Collins & Young Holdings, L.P and the operator of the properties was Devon Energy Corporation. The gas reserves serve to hedge future natural gas requirements for gas-fired generation. In its 2011 annual report, Turlock reported the gas production from its share of the properties was being sold into a local regional market as a hedge to offset purchases of fuel made for the District’s gas generation.

[81] Southern California Public Power Authority, *2005-2006 Annual Report*, 4.
[82] Crowe Horwath LP, *Audit of LADWP’s Contracts for Fuel Procurement and Purchased Power*, June 22, 2012, 16.
[83] Southern California Public Power Authority, *2012 Annual Report*.
[84] Southern California Public Power Authority, http://www.scppa.org/Downloads/Press%20Releases/PressRelease2006-10-26.pdf (accessed: December 2013)

Appendix D: Northwestern Energy's Natural Gas Reserves Acquisitions in Montana

Summary

Northwestern Energy ("NWE") is a gas and electric investor-owned utility serving 269,600 natural gas customers and 403,600 electric customers in Montana, South Dakota and Nebraska. In recent years it has developed a significant natural gas reserves portfolio for its gas business, seeing such resource acquisitions as significantly reducing supply cost variability to its customers. This strategy was developed and articulated in its 2008 and 2010 Gas Procurement Plans and has been supported by the Montana Public Service Commission (MPSC). NWE's current reserves portfolio includes:

- **Battle Creek**
  Announced: 9/22/2102
  Purchase Price: $12.4 M
  Assets: 8.4 Bcf of proven producing reserves plus gathering system
  Cost Recovery Mechanism: Deemed prudent in 2012 Montana Public Service Commission proceeding and included in rate base

- **Bear Paw North**
  Announced: 9/4/2012
  Purchase Price: $19.5 M
  Assets: 13.4 Bcf of proven producing reserves plus gathering system
  Cost Recovery Mechanism: Included in Gas Tracker – filing expected soon with Montana PSE for prudence determination and inclusion in rate base

- **Bear Paw South**
  Announced: 5/28/2013
  Purchase Price: $70.2 M
  Assets: 64.6 Bcf of proven producing reserves plus gathering system and acquisition of Havre Pipeline Company
  Cost Recovery Mechanism: Transaction closed in December 2013. Costs will be included in Gas Tracker with a subsequent filing expected with Montana PSE for prudence determination and inclusion in rate base.

NWE is targeting owning reserves for 50% of its gas supply. With the acquisition of Bear Paw South, a 37% level has been reached and opportunities to close the remaining 13% unfilled position are being examined. NWE expects the Bear Paw South purchase should lock in gas supply at $4.10 per dekatherm for the next 20 years. From this acquisition NWE also expects incremental earning support of $0.06 to $0.10 per share.[85]

Prudence Determination and Cost Recovery Process

NWE recovers costs associated with purchases of reserves in its Natural Gas Tracker mechanism in the near term and then files a subsequent application for a prudence determination inclusion of production costs in Rate Base. Though the MSPC has an optional process for pre-approval, NWE does not see it (a lengthy regulatory process) as accommodating the market-based reserves acquisition process, requiring more rapid action.

Northwestern's prudence case for the Battle Creek acquisition included the following:

- Purchasing reserves and production as its preferred form of long-term hedging was examined and determined in its 2006, 2008 and 2010 Natural Gas Procurement Plans. In the 2010 plan NWE stated its intention to analyze and purchase such assets.
- In its response to the 2008 Plan, the Commission encouraged NWE to examine potential acquisitions of developed natural gas fields.
- In its comments on the 2010 Plan, the Commission stated that failure of NWE to examine such opportunities would be imprudent and that the Commission would evaluate the prudence of NWE's gas procurement activities only on information available to NWE at the time of the acquisition (rather than using hindsight).
- NWE testified that benefits of ownership of natural gas assets include:
    - More stable long-term prices compared to market purchases
    - Potential to increase production if economic conditions allow
    - Reduced portfolio costs when owned production is located on NWE's gas transmission system
    - Improvement to NWE's financial health when assets are rate based
    - Provision of fixed long-term costs rather than short-term fixed contracts available in the market
    - Possibility of net lower costs per dekatherm than market costs

[85] Northwestern Energy, *EEI Financial Conference Presentation*, November 10-13, 2013, pages 13, 20, 21, 33 and 34.

- For evaluating the value of owning natural gas supply assets, NWE used a comparison of prices resulting from its purchase to a long-term market forecast. Using this methodology, NWE calculated the break-even purchase amount to be $13.725 million. The negotiated purchase price was $12.4 million.
- NWE stated that it took measures to reduce risk to customers, including only bidding on proven production reserves, acquiring a facility with experienced operating personnel, facilities in good condition, etc.

Though market prices had declined during the proceeding (reducing the break-even purchase price), the Commission focused only on facts available at the time of the purchase.

The MPSC found that NWE had acted prudently in its acquisition of the Battle Creek properties, affirming NWE's analysis and overall case (including representations of policy support from the legislature and Commission). The Commission went on to state that, "The acquisition of gas reserves is nonetheless a relatively rare practice for local distribution companies. NWE should remain vigilant that it is not exposing itself to undue risks because of market or geological factors, and should monitor the business and operational practices of its few peers in the utility sector that are engaged in gas production."[86]

Excerpts from NWE Documents Regarding Reserves

NWE 2012 Annual Report and 10-K
Regulated natural gas production is not common in the natural gas utility business, but one of our predecessor companies, Montana Power, owned a significant amount of gas production in its day. With natural gas prices at record lows, we've dusted off this approach to manage future price risk and source stability by purchasing proven and producing reserves in Montana.

In 2012, we successfully placed our 2010 purchase of approximately 8.4 Bcf (Battle Creek) into rate base and added another 13.4 Bcf to our natural gas production assets with our 2012 purchase of approximately 600 producing wells in north central Montana (Bear Paw). These acquisitions are consistent with our strategy to provide our customers a long-term source of proven supply that will provide price stability in future years.

[86] Montana Public Service Commission, *In the Matter of NorthWestern Energy's Application to Place the Battle Creek Natural Gas Production Resources in Rate Base and to Recover Associated Expenses*, Docket No. D2012.3.25, Order 7210b, November 16, 2012, 2-13 and 17-21.

We will continue to explore sensible opportunities to add to our regulated electric generation fleet and natural gas production portfolio to help provide price stability to our customers.

Since 2010, we have acquired gas production and gathering system assets as a part of an overall strategy to provide rate stability and customer value through the addition of regulated assets that are not subject to market forces. These owned reserves are estimated to provide approximately 1.8 Bcf each year, or about 10% of our current annual natural gas load in Montana.

We file a biennial Natural Gas Procurement Plan, which provides the MPSC the procurement blueprint we intend to follow to meet our gas supply needs and reliability requirements and hedging strategies used to reduce price volatility. Our last filing was in December 2012.

In March 2012, we submitted an application with the MPSC to place our majority interest in the Battle Creek Field natural gas production fields and gathering system (Battle Creek) acquired in 2010 in regulated natural gas rate base. The application reflected a joint stipulation between us and the MCC of a 10% return on equity and a capital structure consisting of 52% debt and 48% equity. Since November 2010, the cost of service for the natural gas produced, including a return on our investment had been included in our natural gas supply tracker on an interim basis. We received a final order approving our request during the fourth quarter of 2012 and recognized approximately $2.2 million of revenue that we had deferred pending MPSC approval of our application. The deferred revenue represented the difference between our cost of service and natural gas market prices.

During the third quarter of 2012, we completed the purchase of natural gas production interests in northern Montana's Bear Paw Basin, including 75% interests in two gas gathering systems. Together with our existing Battle Creek natural gas production assets, we expect annual production to be approximately 10% of our natural gas load in Montana. The purchase price for the Bear Paw Basin assets including the interests in the two gathering systems (Bear Paw) was $19.5 million (subject to customary post-closing adjustments). Beginning in November 2012, the cost of service for Bear Paw natural gas produced, including a return on our investment is included in our natural gas supply tracker on an interim basis. We are recognizing Bear Paw related revenue based on the precedent established by the MPSC's approval of Battle Creek. We expect to file an application with the MPSC to place our Bear Paw assets in natural gas rate base during 2013 and this revenue is subject to refund until we receive MPSC approval of our application. We expect the Bear Paw acquisition to provide additional margin of approximately $1.9 million in 2013.

Natural Gas Production Assets
In March 2012, we submitted an application with the MPSC to place our majority interest in the Battle Creek Field natural gas production fields and gathering system acquired in 2010 in regulated natural gas rate base. The application reflects a joint stipulation between us and the MCC of a 10% return on equity and a capital structure consisting of 52% debt and 48% equity. Since November 2010, the cost of service for the natural gas produced, including a return on our investment has been included in our natural gas supply tracker on an interim basis. We received a final order approving our request during the fourth quarter of 2012. We are recognizing Bear Paw related revenue based on the precedent established by the MPSC's approval of Battle Creek. We expect to file an application with the MPSC to place our Bear Paw assets in natural gas rate base during 2013 and this revenue is subject to refund until we receive MPSC approval of our application.

Natural Gas Competitive Transition Charges
Natural gas transition bonds were issued in 1998 to recover stranded costs of production assets and related regulatory assets and provide a lower cost to utility customers, as the cost of debt was less than the cost of capital. The MPSC authorized the securitization of these assets and approved the recovery of the competitive transition charges in rates over a 15-year period ending in 2012. The regulatory asset related to the competitive transition charges amortized proportionately with the principal payments on the natural gas transition bonds.

NWE 2010 Gas Procurement Plan[87]

SECTION 5. LONG-TERM HEDGING ASSESSMENT
The procurement plans that have been guiding purchasing and hedging activities for the past five years have focused on each upcoming winter heating season as well as one, two, and three years out. The plans have provided guidance, structure, and discipline to the natural gas supply procurement function. With this procurement timeframe stabilized and functioning properly, it is time to assess long-term hedging strategies, meaning locking in a portion of each year’s supply for a long period of time at known fixed prices. The goal of short-term hedging is to dampen volatility, but it does not provide protection against overall market price trends and movements. Long-term hedging, meaning transactions covering anywhere from 5 to 30 years, provides protection against overall upward price movements or trends by locking in future prices based on

[87] NorthWestern Energy, *Natural Gas Default Supply Procurement Plan*, Montana Public Service Commission Docket No. N2010.12.111, December 2010, 13-15.

market conditions known at the time the transactions are entered into. Such long-term hedging is in addition to price stability already provided by short-term hedging. NWE has determined that ownership of natural gas reserves and production at appropriate prices is the preferred form of long-term hedging and NWE will continue to pursue reasonable opportunities.

Ownership of Natural Gas Reserves and Production

Over the past two years NWE established a process to identify, analyze, and pursue opportunities to purchase natural gas reserves and production. NWE personnel involved in engineering, natural gas transmission, storage, supply, regulatory affairs, marketing, finance, as well as others were called upon to comprehensively identify and evaluate natural gas equity opportunities. A number of properties were analyzed, and on at least four occasions formal offers were extended to owners and later rejected. In the summer of 2010, NWE successfully acquired a majority interest in the Battle Creek Field located in north central Montana. The Battle Creek acquisition is small in relation to NWE's overall natural gas needs; however it provided an excellent opportunity for NWE to gain experience in asset valuation, legal, land and title matters, and other contractual and administrative items involved with acquiring natural gas production and reserves. Importantly, as NWE takes responsibility for the operation of the Battle Creek field, additional knowledge involving operations, maintenance, and development of producing properties will be gained. NWE will continue to pursue opportunities to acquire natural gas reserves and production that make sense operationally and economically, as these investments provide long-term price certainty to customers.

A key consideration for NWE in acquiring natural gas reserves and production assets is timely cost recovery. Because the Battle Creek purchase was market-based, the buy/sell process would not accommodate a lengthy regulatory review process, and NWE could not utilize the Commission's pre- approval process for acquiring natural gas production or gathering resources.

Prior to acquiring an interest in Battle Creek, NWE was purchasing the output from that field under a contract that expired on October 31, 2010, and those supply costs were being recovered in the natural gas tracker. In order to "bridge" the time between the acquisitions and when the Commission has an opportunity to formally consider its costs for inclusion in rates, and after discussions with Commission staff and the Montana Consumer Counsel, NWE included the costs of its share of Battle Creek in the natural gas supply tracker for rates effective November 1, 2010. The November 1, 2010 rates were approved (on an interim basis as with all monthly trackers) as filed. NWE anticipates it will continue recovering Battle Creek costs on this basis until this asset is proposed for rate treatment in a future filing.

NWE intends to continue to analyze opportunities to purchase natural gas reserves and production assets. Similar to Battle Creek, it is highly likely that such opportunities will be priced based on then current natural gas market, resulting in short timelines to submit bids and complete closing, which results in the inability to utilize the pre-approval process provided for under statute. Therefore, in order to better match the time when NWE makes investments and customers commence receiving benefits, with cost recovery, NWE proposes to include the costs of any future acquisitions in the natural gas tracker on an interim basis similar to the approach described above for Battle Creek.

MPSC Approval of NWE 2010 Gas Procurement Plan[88]

Below are excerpts from the MSPC's July 2011 Order reviewing and approving NWE's 2010 Natural Gas Procurement Plan.

Presentation of the Issues

10. Over the past two years NWE established a process to identify, analyze and pursue opportunities to purchase natural gas reserves and production. In the summer of 2010, NWE acquired a majority interest in the Battle Creek field located in north central Montana. The Battle Creek acquisition is small in relation to NWE's overall natural gas needs, but NWE stated it provided an excellent opportunity for NWE to gain experience in asset valuation, legal, land and title matters, and other contractual and administrative items involved with acquiring natural gas production and reserves. In addition, as NWE takes responsibility for the operation of the Battle Creek field, the company will gain additional knowledge involving operations, maintenance and development of producing properties. NWE said it will continue to pursue opportunities to acquire natural gas reserves and production that make sense operationally and economically, as these investments provide long-term price certainty to customers.

11. NWE noted than an important consideration for NWE in acquiring natural gas reserves and production assets is timely cost recovery; however, because the Battle Creek purchase was market based and the buy/sell process would not accommodate a lengthy regulatory review process, NWE could not use the Commission's pre-approval process for acquiring natural gas production or gathering resources.

[88] Montana Public Service Commission, *In the Matter of NorthWestern Energy's Natural Gas Biennial Procurement Plan, Public Service Commission Comments on NorthWestern Energy's December 2010 Natural Gas Biennial Procurement Plan*, Docket No. D2010.12.111, July 27, 2011, 3-5 and 11-13.

12. Prior to acquiring an interest in Battle Creek, NWE was purchasing the output from that field under a contract that expired on October 31, 2010, and those supply costs were being recovered in the natural gas tracker. In order to "bridge" the time between the acquisitions and when the Commission has an opportunity to formally consider its costs for inclusion in rates, and after discussions with Commission staff and the Montana Consumer Counsel, NWE has included the costs of its share of Battle Creek in the natural gas supply tracker for rates since November 1, 2010. The November 1, 2010, rates were approved (on an interim basis as with all monthly trackers) as filed. NWE anticipates it will continue recovering Battle Creek costs on this basis until this asset is proposed for rate treatment in a future filing.

13. NWE intends to continue to analyze opportunities to purchase natural gas reserves and production assets and expects opportunities that arise to be market based, as was the case with Battle Creek and will mean NWE will not be able to use the PSC pre-approval process. Therefore, in order to better match the time when NWE makes investments and customers commence receiving benefits, with cost recovery, NWE proposes to include the costs of any future acquisitions in the natural gas tracker on an interim basis similar to the approach described above for Battle Creek. Plan pp. 13-15.

21. The hedging strategy NWE proposes to use in this Plan has four main elements:

- Use storage to provide reliability and to remove a portion of price volatility;
- Using storage to capture the difference between winter and summer prices for natural gas. The net value of these transactions is credited to customers and therefore reduces rates. This is referred to as "asset monetization";
- Entering into transactions that convert index purchases into fixed values and
- Continuing to pursue opportunities to purchase natural gas reserves and production to provide long-term price stability.

22. These strategies cannot shield customers from natural gas market price trends. NWE currently proposes to have, at a minimum, 55 to 70 percent of the upcoming winter heating season fixed-priced hedged.

Commission Decision

44. This Plan reduces the amount of fixed-for-float transactions (agreements to exchange a future index price for a fixed known value) to 2 Bcf in each of three heating seasons executed at prices less than $7.00/Dkt. The Commission agrees with MCC and NWE in this reduction to layering in fixed-price contracts. Since the 2008 Plan, the natural gas market has undergone enormous

structural change with the development of enormous reserves of natural gas produced from shale formations. This huge increase in reserves has resulted in much lower natural gas prices. While the Commission has no ability to predict future natural gas prices, the unprecedented increase in natural gas reserves indicates that the need to hedge at the levels in the 2008 Plan has clearly declined. While the Commission approves the reduction in the fixed-for- float transactions, it urges NWE to study whether those transactions should be reduced even further in the future with a greater reliance on the use of straight indexed purchases of natural gas. With the vast new natural gas reserves, it may well turn out that purchasing indexed natural gas will provide the customers with lower costs while not exposing them to undue price volatility. The Commission's goal of price stability has changed due the structural changes in the natural gas market.

45. NWE will perform a two-year study on the feasibility and practical value of purchasing call options (which provide an entity the right, but not the obligation to purchase natural gas at an agreed upon strike price in exchange for a premium during the option term) instead of fixed-price swaps. The Commission will evaluate the results of the study when it is completed. The tariffed Natural Gas Procurement Guidelines define hedging as "... activities entered into for the primary purpose of reducing the potential impact of price volatility on customers and includes the use of: natural gas storage and the monetization of natural gas storage; fixed-price contracts that may vary in duration; layering of fixed-price contracts; contracts for the future physical delivery of natural gas; and financial swap agreements that allow settlement reflecting the difference between agreed upon fixed-price and index-price contracts. The Commission explicitly excludes all other financial and derivative hedging activities."

46. Allowing NWE to perform this study does not constitute approval of the use of additional financial hedges by NWE. As noted above, the huge increase in natural gas reserves due to shale gas production suggests that, rather than engaging in further hedging activities, the better strategy may be simply to buy natural gas at indexed prices.

48. The acquisition of the Battle Creek reserves by NWE received comment by CEM and MCC. As pointed out by both NWE and MCC, the subject of cost recovery related to Battle Creek is beyond the scope of this Docket. NWE will make a filing in the future to include the Battle Creek reserves in rate base. At that time parties will have the ability to address the prudence of that NWE acquisition, including a consideration of the performance risk of gas production. Including the cost of the Battle Creek production in the monthly gas tracker filings is an appropriate way for NWE to bridge between the time of the acquisition and a future filing by the company to include the production in rate base.

49. From a planning perspective, the Commission's view on acquiring natural gas reserves or production is unchanged from the comments noted in Paragraph #34 above. Failure to examine the possibility of purchasing reserves given the recent growth in natural gas reserves in the United States and the resulting decline in natural gas prices would not be prudent. Owning natural gas reserves, or owning an interest in them, can result in benefits to ratepayers versus simply buying natural gas at market prices. MCC's comments point out that if this strategy is followed there is no guarantee that it will not necessarily provide protection against rising prices. It is not possible to know what future natural gas prices will be. The procurement of commodities is made on the basis of market information and professional experience. Uncertainty cannot be eliminated. Should NWE pursue the acquisition of major natural gas reserves, it must strive to find transactions which provide compelling customer benefit over buying natural gas at market prices. The main factors that NWE needs to evaluate are volumes, price, and term. Given that a large amount of capital will be required to purchase significant natural gas reserves, the Commission notes that such a transaction will be best presented to the Commission in the form of a stipulated agreement concerning the acquisition between NWE and MCC.

50. Evaluation of the prudence of NWE's natural gas procurement activities will be based solely on information available to NWE at the time transactions were done. Using subsequent market price information constitutes the use of hindsight which has no place in the proper regulatory evaluation of the prudence of procuring natural gas. The Commission also notes that it does not have as a standard that a utility must always purchase a commodity at the bottom of a market cycle. The Commission expects NWE to purchase natural gas following the concepts contained in the 2010 Plan.

51. If NWE adheres to and executes its procurement plan, taking into account the need to remain flexible in its procurement approach, and is able to demonstrate to the PSC's satisfaction that it has done so, then there should be no reason for the PSC to make an imprudence finding. If NWE deviates from the Plan during the tracker year, then NWE must demonstrate to the PSC's satisfaction in the next annual tracker that the decision to deviate from the Plan served the interests of the default supply customers. The PSC will not accept rigid adherence to the Plan in the face of changing market conditions that call for a different course of action. As is always the case in gas tracker proceedings, it remains NWE's burden to demonstrate the prudence of its gas supply acquisition practices.

Appendix E: Glossary of Terms

AGA – American Gas Association.

At the Money – An option with a strike price that is the same as the current forward market price.

Basis – The price differential between the price of a commodity at one location versus the price of the underlying commodity at the primary location.

Basis Risk – The risk that the value of the commodity used as a hedge at one location does not move in line with the underlying exposure of the commodity at the primary location.

Bbl – An abbreviation for “barrel”. A unit of measurement for crude oil.

Bcf – A natural gas volumetric measurement representing one billion cubic feet. One billion cubic feet (1 Bcf) is equal to 1,000,000 Mcf.

BCUC – British Columbia Utilities Commission.

Bid/Ask – A measure of market liquidity, defined as the difference in price between what a buyer is willing to pay (the bid) and what a seller is willing to sell (the ask).

Call Option (also referred to as a Cap) – Provides the buyer the option, but not the obligation, to buy at a pre-determined strike price.

CAPP – Canadian Association of Petroleum Producers.

CCRA – Commodity Cost Reconciliation Account, FortisBC’s commodity rate for customers.

CERI – Canadian Energy Research Institute.

CFTC- US Commodity Futures Trading Commission, a federal agency with oversight of futures and financial derivatives trading.

CNG – Abbreviation for “compressed natural gas”. Natural gas is pressurized to less than 1% of the volume it occupies at standard atmospheric pressure.

Collar – An option structure intended to bracket the contract price between a ceiling price and a floor price; a buyer of a collar purchases a call option and sells a put option.

Correlation – A statistical term describing the relationship between two variables. “Tightly correlated” refers to two variables that move very similarly to one another.

Credit Risk – Financial risk associated with potential default by counterparty.

Delivery Month – The month in which delivery occurs in connection with a transaction between two parties.

Dkt – An abbreviation for “dekatherm”. One dekatherm is equal to 1 million btu or I MMBtu.

Dodd Frank CFTC Regulation – The Dodd Frank Act was signed into law in 2010 to regulate the financial derivatives market.

DOE- US Department of Energy, a federal agency responsible for oversight of US energy imports and exports.

EIA- Energy Information Administration, a division of the DOE that provides energy forecasts and statistics

Exchange (trading exchange) – A platform upon which buyers and sellers can execute physical and/or financial transactions.

Execution – The act of entering into a purchase or sale transaction with a third party.

Extrinsic Value – Represents the additional value of an option contract over and above the intrinsic value.

Farmout – The seller (‘farmor’) sells the interest in the property to the buyer (‘farmee’) who commits to undertake certain actions such as drilling, and the farmor retains a pre-agreed interest in the property. This is a vehicle for the original owner (the farmor) to retain an interest in the property, particularly if the original owner doesn’t have the capital to invest in new drilling.

FERC – US Federal Energy Regulatory Commission, a federal agency with oversight of physical energy markets.

Financial Derivative – A financial instrument whose value is determined by the price of a commodity market index that typically reflects the price of a physical commodity.

Forward Contract – A Forward Contract is an agreement to buy or sell a commodity for future delivery at predetermined time.

Fundamental Analysis – An analysis of supply and demand factors that will influence the underlying price of a commodity.

GIP – Gas in place.

Gigajoule – A metric measurement unit of energy, commonly used in the Canadian gas market**.** 1 gigajoule = 10^9 joules and 1 gigajoule = .947 MMBtu.

Hedge – To hedge is to offset, mitigate or reduce a risk or risks by entering into a transaction with a third party.

Hydraulic Fracturing – The fracturing of rock by a pressurized liquid to extract crude oil, natural gas and natural gas liquids.

Integrated Resource Plan – A utility plan that estimates the future long-term resource requirements given load projections, energy efficiency projections and available generation capacity.

Intrinsic Value – The value that can be locked in for an option at current market prices.

Liquidity – Assessment of the depth of a commodity market, with respect to the ability to execute transactions at prevailing market prices.

LNG – An abbreviation for "liquefied natural gas". Natural gas is converted through intense pressure and cold temperature to liquid, for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas at standard atmospheric pressure.

Long Position – The position of a party that has surplus supply and needs to sell prior to the delivery period.

Margining – Margining is a form of settlement, whereby counterparties agree that a party will post collateral to the other party when the value of an open transaction or set of transactions exceeds a pre-agreed threshold.

Marked to market – A calculation of the value of positions relative to the current forward market prices.

Market Risk – The risk to the portfolio associated with changes in forward market prices.

Mcf – A natural gas volumetric measurement representing one thousand cubic feet. Typically one Mcf is equal to approximately one MMBtu.

MMBtu – A measurement unit of energy, representing one million British thermal units. This unit of measurement is typically used as a unit price in the US gas markets. 1 MMBtu = 1.056 gigajoule.

NEB – Canadian National Energy Board.

Net Position – The net of all "long" and "short" elements within a portfolio.

Option – An instrument that gives the buyer the right, but not the obligation, to buy, or to sell, a commodity at a specified price at some point in the future.

Optionality – A resource or an asset is described as having "optionality" when it is a flexible resource and that flexibility has market value. If a resource is an option or a series of options, it is sometimes referred to as a "real option".

Out of the money – An option strike price that is higher than the current forward market price (for a call option) or lower than the current forward market price (for a put option).

PGA – Abbreviation for "Purchased Gas Adjustment" mechanism. This is a gas cost recovery mechanism for gas utilities.

Portfolio – The aggregation of all supply and delivery obligations, including load, resources, fuel and third party purchase and sale agreements.

PCA, PCAM – An abbreviation for "Power Cost Adjustment" mechanism. A cost recovery mechanism to allow utilities to recover purchased power and fuel. It typically allocates costs between utilities and their customers. Applies chiefly to Pacific Northwest electric utilities.

Put Option (also referred to as a Floor) – Provides the buyer the option, but not the obligation, to sell.

Rate Structure – A rate mechanism for a utility's retail customers.

RPS – refers to renewable portfolio standards adopted on a state level.

Short Position – The position of a party that is deficit supply and needs to purchase prior to the delivery period.

Speculative Trading/Speculation – Speculative trading, also known as proprietary trading, is the deliberate assumption of risk for the purposes of earning trading profits.

Spot Market – The near-term or immediate market for the purchase and sale of a commodity.

Spot Market Price – The price at which purchases and sales are transacted in the spot market; spot market price is often posted in a trade publication.

Stochastic – A type of model that calculates a large number of simulations to provide a distribution of outcomes.

Stress-test – A test to simulate the effect of an extreme event on a portfolio.

Strike Price – The price at which a physical commodity is delivered or a financial payment is made in connection with a financial instrument, when an option is exercised.

Value at Risk – The value that would be realized in an extreme price event, given a specified holding period and an assumed confidence interval.

Volatility – A measure of the rate and velocity at which market prices move up and down.

VPP – A Volumetric Production Payment is an arrangement where a seller delivers gas to the buyer in exchange for an up-front payment. The seller conveys a limited volumetric over-riding royalty interest (i.e., a non-operating interest) in producing fields to the buyer as collateral.

Appendix F: Document Review and Interviews

Figure 40 - Document Review

Long-term Hedging Program Elements	Document Review
Hedging Objectives & Targets	▪ BCUC Meeting Presentations from 2010-2012
Load and Resources	▪ 2013-2014 Annual Contracting Plan
Customer Preferences and Alternative Rate Offerings	▪ Terasen Gas Residential Customer Natural Gas Price Volatility Preferences- Qualitative Research, February 2005 ▪ Alternatives for Managing Natural Gas Price Volatility, October 2012 ▪ Customer migration data report ▪ FortisBC historical customer rate graphs
Medium-Term Price Risk Management	▪ FortisBC report of forward transactions ▪ 2013-2014 portfolio exposure report ▪ Terasen Gas Price Risk Management Plan, January 2011 ▪ Review of Price Risk Management Objectives and Hedging Strategy ▪ BCUC Decision, Order G -120-11 FEI and FEVI Price Risk Management Plan, BCUC Decision briefing document
Long-Term Price Risk Management	▪ FortisBC Energy Utilities 2013 Long Term Resource Plan ▪ Investment in Natural Gas Reserves Briefing Document, September 2011

Figure 41 - Sample Interview Questions

Hedging Program Elements	Sample Interview Questions
Hedging Objectives and Targets	▪ Does FortisBC have a defined risk tolerance? ▪ How far forward did FortisBC used to hedge with physical and financial contracts? ▪ What were FortisBC's annual hedging targets? ▪ How was hedging program success previously defined? ▪ How do you use storage as a price risk management tool?
Load and Resources	▪ What updates will you be making to your new gas acquisition plan and resource plan? ▪ How is your portfolio changing over time? ▪ How much can you load forecast vary on an annual basis? ▪ Please describe seasonal load variability in your portfolio.
Customer Preferences and Alternative Rate Offerings	▪ How do current rate mechanisms smooth rate volatility for customers? ▪ What kind of customer research have you conducted? How was it structured? ▪ What topics were discussed with customers? What were the results of the survey work? ▪ Who are current third-party marketers and what products do they offer? ▪ What type of customer attrition has occurred? ▪ What has been the history of retail access in your service territory? ▪ What type of rate structures have customers favored? ▪ What is the risk tolerance of customers to rate increases?
Medium-Term Price Risk Management	▪ What have commission staff and interested parties said about your prior hedging program and the 2011 proposed Price Risk Management Program? ▪ What instruments have you used in the past to hedge?

Hedging Program Elements	Sample Interview Questions
	▪ What are the most liquid instrument and markets for hedging? ▪ Are there any utilities hedging programs you are particularly interested in?
Long-Term Price Risk Management	▪ Have you explored long-term hedging options? ▪ What type of support would there be for long-term price risk management options?

Appendix G: Consultants' Resumes

JULIA M. RYAN (PROJECT MANAGER)

jryan@aetheradvisors.com

Energy industry executive with proven leadership skills and record of achievement in risk management and strategic planning. Experienced in project management, portfolio analysis, business start-ups, M&A initiatives, trading & origination. Collaborative leader, providing strategic vision to power and natural gas companies as well as insight to complex risk management issues.

PROFESSIONAL EXPERIENCE

AETHER ADVISORS LLC
Seattle, Washington 2012-Present, 2006-2011

Managing Partner
Established Aether Advisors LLC to provide advisory services to senior executives of regulated and non-regulated energy companies. Provided hedging advice and conducted risk management reviews for utilities. Developed strategy for utility, merchant power, competitive retail marketer, and energy trading clients. Provided investment advice and due diligence services to private equity and merchant power clients.

CONCENTRIC ENERGY ADVISORS INC.
Seattle, Washington 2011-2012

Vice President
Led the firm's Risk Management practice and was responsible for business development and the delivery of advisory services to clients. Reviewed the tools, techniques, and decisional documentation of utilities' risk management programs. Reported to president.

PUGET SOUND ENERGY
Bellevue, Washington 2001-2006

Vice President, Risk Management and Strategic Planning (8/2005-2/2006)
Directed "Risk Operations", consisting of Corporate Budgeting, Credit Risk Management, Energy Risk Control, and Internal Audit. Managed 25 professional staff. Implemented Company's enterprise risk management framework. Executive member of the following oversight committees: Disclosure Practices, Risk Management, Sox 404, Ethics and Compliance, Energy Resources, Emissions Marketing, and Financial Outlook. Reported to CFO.

Vice President, Energy Portfolio Management (12/2001- 8/2005)
Managed the utility gas portfolio as well as the utility electric portfolio (hydro, coal generation, gas-fired generation, and market purchases). Led 35-40 professionals in risk management, quantitative analysis, financial analysis, and trading. Reported to CFO.

TRANSALTA USA (FORMERLY MERCHANT ENERGY GROUP OF THE AMERICAS)
Annapolis, MD 1997- 2001

Managing Director, North American Marketing (formerly Managing Director, Origination)
One of the four principals who developed a North American marketing, trading and merchant power business plan and entry strategy for parent companies, Gener S.A. and TransAlta. Reported to CEO of Merchant Energy Group, and later to TransAlta CFO.

LOUIS DREYFUS CORPORATION
Wilton and Stamford CT, Winnipeg MB, and Kansas City KS 1984-1997

Senior Vice President, Duke/Louis Dreyfus L.L.C., Wilton, CT (2/96-6/97)
Conceptualized business plan for joint venture marketing alliances, national accounts and regional accounts. The products and services developed included derivatives products, energy management outsourcing, supply portfolio hedging, tariff analysis and fuel consumption analysis. Reported to Executive Vice President.

Vice President, Louis Dreyfus Corporation, Wilton, CT (4/89-1/96)
Established the Company's natural gas trading and marketing division in 1989. Largest profit area was linked to long-term sales, hedged with futures and natural gas producing properties. Reported to President.

Merchant, Louis Dreyfus Corporation, Kansas City KS, Winnipeg MB, Stamford CT (6/84-3/89)
Diverse trading career in domestic and international agricultural commodity markets.

EXTERNAL

- Strategic Advisor to A PLUS Youth Program| A Washington State Non Profit (2013-Current)
- Appointed to Seattle City Light Review Panel (2010- current)
- Guest instructor at the Atkinson Graduate School of Management, Willamette University. Currently co-director for the "Utility Management Certificate Program" (2006 – current).
- Guest speaker at industry conferences on risk management (2006- current)
- Authored articles on utility hedging and risk management for <u>Public Utilities Fortnightly</u> (2012) and <u>Wiley Periodicals</u> (2009-2010)
- Board member of the Northwest Gas Association (2002-2006)
- Extensive presentation experience with Company boards, state regulators, major customers and elected officials

EDUCATION

SMITH COLLEGE, Northampton, MA
B.A. English, 1984 Smith College, Northampton, MA.
Cum Laude and Phi Beta Kappa

Aether Advisors LLC

JOSHUA WEST (CONSULTANT)

josh@jwestenergy.com

SUMMARY OF QUALIFICATIONS

Energy industry professional with expertise in the hedging, valuation, structuring and analytics of complex energy derivatives and energy Company portfolios. Unique ability to integrate physical energy exposure with financial derivatives modeling and risk management. Over 9 years of additional experience in modeling, quantitative analysis, option pricing theory, fundamental analysis, asset acquisitions and divestures, credit risk management, and business development.

PROFESSIONAL EXPERIENCE

J. WEST ENERGY LLC
Seattle, Washington 2012-Present

Principal Consultant

Consulting in strategy, valuation, and analysis of structured transactions in the physical energy space. Target clients include utilities, merchant energy companies, private equity firms, retail energy providers, and other consulting/legal firms.

- Assisted a competitive retail electric provider with industry best practices in the pricing of full-requirements load, hedging strategies for variable volumetric risk due to weather and customer migration, and use of financial derivatives to hedge load risks.

J.P. MORGAN GLOBAL COMMODITIES, ENERGY DIVISION
Houston, Texas 2008-2012

Vice President

Worked within the structuring group supporting the trading and marketing physical natural gas, power, coal, weather, and emission products throughout North America. Clients included utilities, cooperatives, municipalities, merchant energy companies, private equity firms, hedge funds, and other trading and marketing firms.

- Led the structuring of complex transactions including a wide array of physical and financial transactions such as tolling agreements, asset acquisitions, wind derivatives, full-requirements load, natural gas storage and transport, and various complex option products.
- Develop trading and hedging strategies for large structured power transactions. Derived market-implied volatility and correlation curves.
- Provide leadership for all aspects of structured trades including initial concept, valuation, credit analysis, strategic objectives, contract negotiations, risk metrics, booking, and on-going position management.
- Communicate key deal attributes to upper-level management and cross-functional team members. Coach junior team members to develop their understanding of our business and develop our talent pool.

INTERNATIONAL POWER
Marlborough, Massachusetts 2006-2008

Structured Transactions

Part of team responsible for the valuation and optimization of Company's natural gas and coal generation assets and due diligence and valuation of potential acquisitions. Responsible for general analytics, quantitative modeling and asset hedging using financial derivatives.

- Structured and evaluated complex financial derivatives and physical transactions that optimized the value of the Company's physical assets.
- Modeled and evaluated physical assets for acquisitions and divestures.
- Coordinated and led discussions with business development, origination, trading, legal, and accounting, credit and engineering.

LIBERTY POWER CORP
Ft. Lauderdale, Florida 2006

Manager, Structuring and Risk Management
Responsible for the development of a portfolio management system to capture and manage the inherent risk of serving fixed price full requirements load.

- Assisted with the structuring and closing of a large credit facility that enabled the Company to increase free cash flow and reduce collateral requirements.
- Priced and evaluated full-requirements load transactions in competitive power markets with retail access.
- Developed hedging strategies for underlying market exposure and variable volumetric risk due to weather and customer migration.
- Built a portfolio management system from the ground up which contained position reports, risk management metrics, stress scenarios, and necessary models.

PUGET SOUND ENERGY
Seattle, Washington 2004-2006

Structuring and Risk Management
Part of the portfolio management team responsible for structuring, analytics, modeling, fundamental analysis, and risk management. The Company's portfolio consisted of natural gas and power load, natural gas transportation and storage, natural gas and coal generation, wind and hydro generation, and hedges for their net short.

- Structured and valued complex energy transactions that enhanced the regulated utility's supply portfolio value and reduced the Company's exposure to market risk. Presented the results and impacts of financial derivatives transactions to upper-level management.
- Developed econometric and stochastic models for valuation of transactions and to perform scenario analysis for portfolio hedging strategies.
- Developed fundamental analysis summaries from historical data, trade publications, and public information. Created and wrote the Company's internal fundamental natural gas and power report.

EDUCATION

KENT STATE UNIVERSITY, Kent, Ohio
B.B.A. Economics - 2001
Cum Laude

UNIVERSITY OF NEW MEXICO, Albuquerque, New Mexico
M.A. Economics – 2003, Concentration: Econometrics

GEORGE POHNDORF (CONSULTANT)

gpohndorf@comcast.net

SUMMARY OF QUALIFICATIONS

Energy executive with over 15 years of senior leadership experience across a diversity of strategic functions including Regulatory Affairs, Strategy Development, Energy Resource Planning, Smart Grid and Demand Response, Major Accounts Marketing and Customer Services, Energy Efficiency and Sustainability and Public Policy.

PROFESSIONAL EXPERIENCE

G. POHNDORF & ASSOCIATES
Seattle, Washington 2013- Current

Principal
Providing expertise and client services in strategy development, utility regulation, finance, economics, energy resources, energy policy and stakeholder engagement.

PUGET SOUND ENERGY
Bellevue, WA

Director, Community and Business Service 2011 – 2012
Developed and led an integrated customer service and regional team as well as major accounts strategy and initiatives.

- Developed and negotiated successfully comprehensive bid to retain PSE's largest customer with local PUD competitive option, integrating operational, regulatory, transmission and customer service elements.
- Developed and implementing external strategy to support LNG facility supporting maritime and transportation markets. Assisted in the development of market, product and regulatory strategy.
- Led community customer engagement initiatives targeting residential and small business markets.
- Negotiated power purchase and transmission arrangements with Shell to address expiring PURPA contract.

Director, Major Accounts and Business Account Services 2005 – 2011
Built a nationally-leading business customer service team, achieving best-in-class evaluations from Fortune 50 firms and local institutions through comprehensive management of largest customers, representing $720M in annual revenues.

- Expanded customer service offerings and engagement through cross-functional leadership while achieving productivity at over three times industry standards.
- Expanded customer engagement (from top 80 to 600 customers) and performance with no increase in staff.
- Led energy efficiency market development and program expansion through extensive customer collaboration.
- Engaged and advised customers on sustainability, carbon, renewables and emerging technology strategies.

- Led the development of over 40 tailored products and services to major customers, including energy efficiency offerings, energy and cost management tools, sustainability services, outage communication and restoration protocols, advisory services, rates and tariff services, billing solutions and specialized construction services.
- Developed customer support for company initiatives through strategic collaboration and engagement. Examples include: integrated energy efficiency and energy resource acquisition programs, three general rate cases and three power cost cases from 2005-2010, including recovery of 773 MW ($1.5B) in wind investments.

Director, Regulatory Initiatives 2003 – 2005

Successfully led the development and achievement of strategic initiatives to reposition PSE through building corporate capabilities across multiple organizations, extensive external collaboration and ensuring successful implementation.

- Led the creation of PSE's integrated resource planning and acquisition processes and developed full stakeholder and regulatory support for an expansive energy efficiency and resource program.
- Led negotiation and collaboration with NWEC and stakeholders on Washington Energy Portfolio Standard.
- Ensured full cost recovery of 996 MW in thermal acquisitions and 773 MW in wind investments. These included PSE's Frederickson I, Sumas, Goldendale and Mint Farm thermal acquisitions and PSE's Hopkins Ridge, Wildhorse Phase I, Wildhorse Phase II and Lower Snake River wind acquisitions.
- Led achievement of general rate case results to provide further support for rebuilding PSE's financial strength.
- Led power cost rate case to create replicable template to achieve prudence findings and contemporaneous recovery of ensuing resource acquisitions over the next decade.

Director, Regulatory Affairs 1999 - 2003

Responsible for regulatory results impacting over $2 billion in company revenues. Directed the development and implementation of regulatory and external initiatives to create opportunities and address threats throughout industry restructuring, including energy resource planning, open access strategy, energy efficiency strategy, smart grid strategy, holding company and subsidiary creation and generation contract restructurings.

- Led energy efficiency policy, program development, regulatory and stakeholder negotiations. Collaborated in the successful and rapid expansion of energy efficiency investments and portfolio.
- Led comprehensive strategic initiatives to ensure corporate financial success during and following the Western Energy Crisis. These included:
  - An expansive general rate proceeding that achieved: short-term interim and general rate relief, a power cost adjustment mechanism, a new energy efficiency planning and implementation mechanism, new energy resource cost recovery mechanism, capital structure mechanism and successful resolution of demand response issues with results achieved through comprehensive settlements.
  - The development and regulatory approvals for PSE's time of use demand response program, winner of the Edison Award and the most comprehensive program in the nation at that time.
  - Negotiated resolution of market-based retail wheeling program for industrial customers.
- Successfully negotiated numerous solutions as lead company liaison to state regulatory commission, state and federal agencies, customer groups and environmental groups.
- Directed strategic coordination of external initiatives among regulatory, communications, legislative, governmental and community affairs functions.
- Managed regulatory proceedings to secure favorable treatment of $197 million Centralia generation asset sale producing cost savings of $27 million and removing associated environmental and cost liabilities as well as Encogen and Tenaska PURPA cogeneration contract restructurings.

Director, Special Projects 1998-1999

- Successfully developed and coordinated strategic initiatives, integrating among external affairs and business planning, marketing, sales, finance, and operations functions.

- Led initiative to reposition corporate strategy to address technology and market change.
- Served on strategy team that secured $250 million allocation of federal hydropower benefits for PSE customers through integrated commission, BPA, legislative and residential customer engagement.
- Served on team to address successfully municipalization challenges through integrated political, regulatory, legal, customer and stakeholder strategy. Achieved approvals of resulting customer special contracts.
- Developed and achieved commission approval for holding company structure and subsidiaries creation.
- Successfully developed $35 million energy efficiency program, securing support from all parties including industrial customers, commercial customers, consumer and environmental advocates and state regulators.

Director, Resource Planning 1997 – 1998

- Served on Board of Directors of the Northwest Energy Efficiency Alliance, launching the nation's leading "market transformation" organization, with budget of $65 million.
- Developed stakeholder support and regulatory approval for energy supply initiatives in support of corporate strategy to address industry restructuring. Successfully led company stakeholder processes supporting regulatory approvals.
- Secured regulatory approvals for PSE's innovative $240 million conservation asset securitizations.
- Negotiated legislative approaches to industry restructuring with industrial customers, environmental groups, consumer advocates, public utilities and other investor-owned utilities.

Senior Strategic Planning Analyst/Planning Analyst 1991 – 1997

- Served on case strategy team achieving approval of $4.2 billion 1997 merger between Puget Power and Washington Natural Gas.
- Performed financial and policy analysis of strategies to address emerging corporate risks and opportunities. Assumed a lead role in development of resulting regulatory and political strategies.
- Served on case strategy team to achieve recovery of PURPA contracts in 1993-1994 WUTC prudence review.
- Managed Puget Power's integrated resource planning and external collaboratives to support plan development. Created and implemented new resource planning model.

EXTERNAL

- Board Member, NW Energy Coalition (1997-Current), Treasurer and Executive Board Member (2003-Current)
- Finance and Economics Guest Instructor, Willamette University Executive Development Center (2013-Current)
- Board Member, Northwest Energy Efficiency Alliance (1997-2000)

EDUCATION

UNIVERSITY OF PUGET SOUND, Tacoma, WA
B.A. MATHEMATICS
Magna Cum Laude, Phi Beta Kappa, Phi Kappa Phi

WILLIAM E. SIMON GRADUATE SCHOOL OF BUSINESS ADMINISTRATION, Rochester, NY
MASTER OF BUSINESS ADMINISTRATION, Finance
Summa Cum Laude, Kalmback Scholar, Beta Gamma Sigma

Appendix H

GAZ METRO'S REVIEW OF FINANCIAL DERIVATIVES PROGRAM

PROPOSALS FOR A

FINANCIAL DERIVATIVE PROGRAM

(Follow-up to Decision D-2012-158)

TABLE OF CONTENTS

GLOSSARY OF TECHNICAL TERMS

AECO	Point located in Alberta representing the well production accumulation point.
Collar	Financial derivative simultaneously comprising the purchase of a call option and the sale of a put option. In a no-fee collar, the exercise price of both options may be chosen in a way that there is no premium payable at the signing of the collar.
Dawn	Point located in southern Ontario.
Henry Hub	Point located near the Gulf of Mexico used as a delivery and reception point for "futures" on the NYMEX stock exchange.
Call option	Financial derivative conferring the right, but not the obligation to purchase at a future date a certain quantity at a set price in return for a premium payable at the time the transaction is carried out.
Put option	Financial derivative conferring the right, but not the obligation to sell at a future date a certain quantity at a set price in return for a premium payable at the time the transaction is carried out.
Intrinsic value	Settlement amount of the financial derivative, supposing that it is exercised under current market conditions.
Market value	Value of the financial derivative in function of the current market conditions.

1 BACKGROUND

Gaz Métro Limited Partnership's ("Gaz Métro") financial derivative program (the "Program") was implemented in October 2001 pursuant to a proposal by Gaz Métro in conjunction with the 2002 Rate Application (R-3463-2001) approved by the Régie de l'Énergie (the energy regulation authority - "Régie") in its Decision D-2001-214. Since its entry into force, each year Gaz Métro has applied the Program according to the parameters approved annually by the Régie. The Program has been slightly modified over the years to reflect changes in the market context.

In Phase 1 of the 2013 Rate Application (R-3809-2012), in addition to the elements usually submitted to have the Program's parameters approved for the 2012-2013 fiscal year, Gaz Métro submitted a reflection on the Program resulting from the market context at that time. Pursuant to the submission of said reflection, Gaz Métro answered several requests for information from the Régie and various stakeholders.

In its Decision D-2012-158 rendered on November 23, 2012, the Régie suspended application of the Program and asked Gaz Métro to present a proposal aimed at maintaining, reformulating, or suspending the Program based on the recommendations of an outside consultant at the latest during the 2014 Rate Application:

> "[80] ***For all these reasons, the Régie orders Gaz Métro to submit an assessment of the financial derivatives program produced by an outside consultant on these questions and to formulate a proposal to the Régie based on the expert report.***" [1]

More specifically, the Régie formulated three distinct requests pertaining to the Program in its Decision D-2012-158.

<u>Request #1</u>: Proposal based on the recommendations of an independent expert.

The Régie specifically requested that the following elements be covered in the expert report:

> "[80] […] ***This report must take into account the elements previously brought up by the Régie and specifically examine the following elements:***
>
> - ***The costs and benefits to clients of the current financial derivatives program***

[1] D-2012-158, page 21

- ***The advantages and inconveniences of maintaining a financial derivatives program***
- ***The possibility of ending the program***
- ***The benchmarks of any potential reformulated program to take into account the current context of natural gas prices***
- ***The management of migrations between direct purchase and network gas services***
- ***The benchmarking in terms of the use of financial derivatives in the energy sector***
- ***The Expert recommendation regarding best practice in the management of financial derivatives.***" [2]

To respond to this request by the Régie, Gaz Métro sent a call for tenders to several firms in order to select an independent expert and chose Concentric Energy Advisors ("Concentric") to carry out the analysis. Gaz Métro is therefore submitting the report by Mr. Ruben Moreno, Assistant Vice-President at Concentric, the independent expert (the "Expert") for this application (Gaz Métro 6, Document 1).

The report covers each element listed above and Gaz Métro proposes, in this document, new parameters to adapt its Program according to the Expert recommendations.

Request #2: *Assessment of Alternatives to the Program*

In its decision, the Régie also asked:

> "[82] ***In the elaboration of its proposal, the Régie asks Gaz Métro to assess and identify the various alternatives that could enable them to offer price stability to their clients and to evaluate the anticipated costs and benefits resulting from these alternatives.***" [3]

Gaz Métro has identified seven possible alternatives to the Program and analyzed the advantages and inconveniences for each one. The results of these analyses are presented in Section 7.

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[2] D-2012-158, page 21

[3] D-2012-158, page 21

Request #3: *Assessment of Customer Needs*

In the same decision, the Régie also mentioned that it would be useful to have an assessment of client needs in terms of price stability and protection against price spikes.

> "[76] ***In addition, the Régie is of the opinion that the program's objectives must be assessed by taking into account the verified needs of the network gas clients in terms of protection against price volatility and spikes. Thus, it deems that it would be useful to have an assessment of client needs in regards to price stability and protection against price spikes. It is not convinced that efforts have been made in this regard to assess the exact needs of network gas clients and their sensitivity to the cost of protection against price spikes.***" [4]

Gaz Métro retained the services of an outside firm, Extract Recherche Marketing ("Extract"), to carry out a survey of its clients. The results of this survey are summarized in Section 2.2 and the complete report is presented in Appendix D.

1.1 Gaz Métro's Aim

By virtue of Article 52 in the *Act respecting the Régie de l'Énergie* (the "ARRE"), the supply rate, prices and other conditions applicable to a consumer or a group of consumers shall reflect the actual acquisition cost. Thus, the risk resulting from fluctuations in the price of natural gas is to be borne by the clients. With the Régie's permission, Gaz Métro, in the past, has used financial derivatives to control said fluctuation risk.

Gaz Métro has never received a direct advantage from its Program. Gaz Métro's only interest in implementing this Program is to meet one of the needs of its supply service customers, which is that of being protected against natural gas price fluctuations. The proposal described in this proof uses the same logic.

1.2 Description of the Proof

Section 2 presents the arguments for the reactivation of the Program, containing, among other things, the elements in the Expert report and the results of the customer survey.

[4] D-2012-158, page 20

Based on the Expert recommendations, Section 3 describes the Program proposed by Gaz Métro and presents its parameters. This section identifies the Program's objectives, specifies how the risks are assessed and describes under what conditions the financial derivatives shall be used to reduce the risks deemed to be undesirable.

Section 4 covers the operationalization of the proposed Program, gas supply strategies and the processing of transactions carried out before Decision D-2012-158. In Section 5, Gaz Métro lists the methods that would allow the Régie and stakeholders to monitor the Program.

Section 6 presents the arguments justifying the fact that the Program should apply to all supply service customers.

Finally, Section 7 presents various alternatives to a financial derivatives program that would make it possible to offer price stability, and an assessment of the anticipated advantages and disadvantages resulting from each of the alternatives, as requested by the Régie in its Decisions D-2012-158.

2 JUSTIFICATIONS FOR A FINANCIAL DERIVATIVES PROGRAM

The purpose of this section is to justify the relevance of reactivating the Program to protect Gaz Métro's supply service customers.

2.1 A Perspective is not Protection

The decrease in the price of natural gas in North America since the summer of 2008 has had a major impact on all the natural gas players. This decrease has also had an impact on the perceptions held by the regulatory authorities and the stakeholders on the financial derivatives programs implemented to protect customers against price increases. The natural gas price perspectives have even led some to conclude that the North-American market has reached a new equilibrium characterized by low, stable prices and, for this reason, financial derivatives programs are no longer useful.

However, as mentioned in the Expert report[5], a perspective does not offer protection. The changes in the price of natural gas are a good example. In 2007, the market prices reflected the anticipation that the prices of natural gas would remain high and volatile, justifying among other things, significant investments in several liquefied natural gas importation projects. Then just one year later, prices started an almost constant decrease, which lasted until 2012, going from $11.24/GJ on July 1, 2008 to $1.43/GJ on April 20, 2012[6].

Gaz Métro therefore underscores that the forecasts indicating relative price stability for natural gas are not a guarantee that significant changes will not occur in the natural gas market. If in 2007 and 2008, the natural gas market was wrong in its forecast for high, volatile prices, how can it be presumed that the natural gas market in 2013 will not be wrong in its forecast of stability? The drastic increase in prices that occurred in 2000 and 2001 is also a good example where the market prices reached unforeseen levels, forcing Gaz Métro to completely rework its Program that had become inefficient in this new context. The purpose of a financial derivatives

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[5] Gaz Métro-6, Document 1, Question 56

[6] Spot price at AECO, Source: Bloomberg

program is to reduce the impact on customers of unforeseeable price changes and the Expert report is very persuasive in this regard.

In addition, according to the Expert report, a financial derivatives program represents an efficient method to protect customers against price increases.

The Expert report confirms that there are energy distributors in North America who use financial derivatives to protect their customers from energy price increases. Appendix B to the Experts report mentions five distributors who use best practice in risk management in conjunction with their financial derivatives program[7].

2.2 Customer Survey

As suggested by the Régie in its Decision D-2012-158, Gaz Métro retained the services of an expert in the field to survey its customers' needs for protection against fluctuations in natural gas prices. This subject is very complex to survey, especially since Gaz Métro's customers are not familiar with this kind of concept and are not even aware of the existence of the Program. Extract therefore proposed a two-phase survey methodology in order to obtain valid data from the customers surveyed.

2.2.1 Survey Methodology

The two phases of the methodology used by Extract to survey Gaz Métro's clients include a telephone survey and in-depth interviews.

Telephone survey:

- 885 respondents (664 business and residential supply service customers as well as 221 non-customers) surveyed by telephone
- This allowed simple concepts to be quantified and assessed providing general information about financial derivatives as well as detailed information on price sensitivity.

In-depth interviews:

[7] Gaz Métro-6, Document 1, Appendix B

- 30 supply service business customers and 5 supply service residential customers were surveyed by an in-depth telephone interview that lasted 30 minutes on average with support material on the Internet.
- Following comments made during the technical meeting held on June 17, 2013, an additional 25 residential customers were surveyed according to the same methodology.
- The 60 in-depth interviews went further into the more complex concepts, such as the explanation of the Program.

2.2.2 Analysis of Results

The main observations made by Extract are the following:

- Among the supply service customers, the vast majority state that they are concerned by a variation in their bill of more than 10%.
- Among the supply service customers who are not registered on the equal payment plan, 20% would prefer a more stable bill.
- The results of the quantitative research show that presently there is some confidence regarding the stability or a small increase in natural gas prices for the next three years. In fact:
  - A significant proportion of customer respondents (74%) believe that natural gas prices will remain stable over the next twelve months and will increase a little over the next three years
  - Only one third of customers say they are very or quite concerned by the price of natural gas.
- Since the Program is not well known at all, customers needed detailed explanations to be able to express an informed opinion on their preferences about protection against variations in natural gas prices. In fact, a general interest question about the subject was asked during the telephone survey. When asked, the majority of customers surveyed did not wish to belong to a protection program; not because they were not interested, but rather, as several mentioned, because they do not have

enough information at their disposal to make an informed choice by telephone survey.

- For this reason, Extract recommends that the results of the 60 in-depth interviews be used to find out a valid opinion from Gaz Métro's customers about the Program. After an explanation lasting about 10 minutes about the Program, here are the main results obtained from the participating customers:
  - Customers have a tendency to prefer being protected (48/60) against possible price increases. Even if it is not their main concern, it would afford them budgetary stability
  - In addition, a majority of the respondents (32 out of 60) would choose a "gold" level of protection, which is a level higher than that offered by Gaz Métro's Program over the last few years. The "silver" protection level, similar to the Gaz Métro Program's historical protection level, is favoured by 12 respondents out of 60.

The table below summarizes the study's main observations. The detailed study results are presented in Appendix D to this document.

Table 1: Survey Results per Customer Segment

	Choice	**Residential customers (n=30)**	**Business customers (n=30)**
Confident regarding an increase in natural gas prices	**Will increase a bit** or **Will remain stable**	90%	86%
Ability to forward plan their consumption of natural gas	**Very easy** or **Quite easy**	83%	73%
Protection level preference	**Gold protection** or **Silver protection**	77%	70%

In light of these analyses, Gaz Métro concludes that protection against fluctuations in natural gas prices is a real need for its customers, both residential as well as business. By adding the "gold" and "silver" protection levels together, Gaz Métro observes that 73% of the customers (44 out of 60) choose a protection level that is at least similar to the Program's protection levels over the last few years.

2.3 Interviews with customer representatives

In its service proposal, the Expert offered to interview representatives of the Régie as well as the various stakeholders regarding Gaz Métro's Program. Gaz Métro authorized the Expert to carry out these interviews because they would supplement the survey that was carried out directly with Gaz Métro's customers by Extract.

The Expert therefore carried out interviews with the various customer representatives. The Union des consommateurs (UC - Consumers Union), Option consommateurs (OC - Consumer Choice), the Union des municipalités du Québec (UMQ - Union of Quebec Municipalities) and the Canadian Federation of Independent Business (CFIB) agreed to answer the interview questions. The Industrial Gas User's Association (IGUA) declined the invitation on the basis that it has very few or no customers who use Gaz Métro's supply service. The Régie did not participate in the interviews.

The following main observations may be drawn from the interviews with the customer representatives:

- None of them want the Program to be terminated
- Commercial and municipal customers want predictability and price certainty, and favour fixed prices.
- Residential customers want price protection. There is also a concern that price decreases would not be reflected in the rent for low-income tenants
- They favour the possibility for the customer to be able to choose the desired level of protection depending on their risk acceptance level
- The multi-year fixed price option was raised several times
- Concern for locked-in customers of Gaz Métro's supply service
- Concern about the customers' ability to make an informed choice.

Gaz Métro concludes that the customer representatives are favourable to maintaining a financial derivatives program, as long as it more adequately meets the customers' needs. Gaz Métro notes that some stakeholders share Gaz Métro's concern about residential customers' ability to make informed decisions on this subject[8].

Appendix D to the Expert report presents a more comprehensive summary of the interviews that it conducted with customer representatives.

2.4 Financial Derivatives Program as an Efficient Solution

To conclude this section, given:

- The customers' need for protection from price increases being confirmed by the survey
- The interest shown by the representatives interviewed by the Expert in pursuing a financial derivatives program
- The effectiveness of financial derivatives to meet the customers' need for protection, as mentioned in the Expert report

Gaz Métro requests that the Régie reactivate the Program that was suspended in its Decision D-2012-158 with the modifications proposed by the Expert in his report.

In the next section, Gaz Métro shall describe and explain the new parameters for this Program, which take into account the Expert recommendations as well as the concerns of the Régie and the stakeholders.

3 PROPOSAL FOR A MODIFIED PROGRAM

In order to improve the Program pursuant to observations made by the Expert, answer the concerns expressed by the Régie and the stakeholders and comply with best practice in terms of risk management, Gaz Métro proposes that the Program be reactivated, with parameters based on the recommendations made by the Expert.

[8] Gaz Métro-6, Document 1, Appendix D

3.1 Principles of the Proposed Program

The proposed Program would be based on the following three elements:

- Identification of risks and quantification of objectives
- Quantitative assessment of risks
- Hedging strategy to prevent undesirable exposure to risks.

The Program would therefore consist in identifying the risks to be avoided and quantifying the objectives to be met for customers, measuring the exposure to undesirable risk, and finally, implementing a financial derivative purchase strategy to reduce said exposure. These elements are described in more detail in the following sections.

3.2 Identification of Risks and Quantification of Objectives

The Program's first step would comprise identifying the risks targeted by the Program and defining the objectives that the Program would be targeting.

3.2.1 Identification of Risks

As mentioned in the Expert report, best practice in terms of risk management takes into account both the risk of price increases as well as the risk of opportunity losses. Gaz Métro believes that these two objectives are relevant for its Program.

During the interviews with supply service customer representatives carried out by the Expert, it was shown that they are mainly concerned with catastrophic risks, i.e. natural gas price spikes that would have a significant impact on their bills. In compliance with the Expert recommendations and the stakeholder representatives' concerns, Gaz Métro therefore proposes that the Program's main objective be the reduction of exposure to catastrophic risk.

In conjunction with the requests for information for the 2013 Rate Application, the Régie expressed its concern for the opportunity losses in the framework of Gaz Métro's Program[9]. The interviews conducted by the Expert also highlighted customers' concerns regarding

[9] R-3809-2012, 2013 Rate Application, B-0092, Gaz Métro-5, Document 1, Question 30.

opportunity losses[10]. In compliance with the Expert recommendations and the stakeholders' concerns, Gaz Métro proposes that limiting opportunity losses be the underlying objective for the Program.

These two objectives are partially contradictory. In fact, financial derivatives that are contracted to reduce exposure to price spikes are responsible for the risk of opportunity losses in the event of a price drop. The relationship between both aims would therefore limit both the quantity as well as the type of financial derivative contracted in order to minimize the risk of opportunity losses. The "underlying" character of this second objective would reflect the fact that the opportunity losses would be created by the financial derivatives used to attain the main objective; without the main objective, there would be no need to define the underlying objective.

3.2.2 Quantification of Objectives

Before going on to the risk assessment step, it is necessary to assign a quantitative value to the objectives proposed in the previous section. This quantification would correct one of the weak points identified by the Expert, i.e. the vague nature of the current Program aims. The purpose of this quantification would in fact be to clearly identify what an undesirable increase and undesirable opportunity loss would be, thus allowing the risks to be assessed objectively and the decision-making to be justified by these assessments. Gaz Métro proposes the use of the method recommended by the Expert in his report, i.e. setting limits in function of distribution percentiles for natural gas prices, while assuming that the prices of natural gas follow a log normal distribution. Also according to the Expert recommendations, Gaz Métro proposes the use of the 99th percentile to estimate the benchmarks.

[10] Gaz Métro-6, Document 1, Appendix D

The benchmark for price increases would be calculated according to the following formula[11]:

$$BHP_t = F_t * \exp(\alpha_{99} * \sigma_t) \quad (1)$$

Where: BHP_t is the price increase benchmark for month t, expressed in $/GJ

F_t is the price for the forward contract for month t, expressed in $/GJ,

exp() is the exponential function

α_{99} is the 99th percentile of the standard normal distribution, and

σ_t is the historical volatility of the price logarithm for month t.

The historical volatility of the natural gas price logarithm would be calculated by using the price data for the 40 working days prior to the benchmark calculation date. The price increase benchmark would thus be defined as the absolute price level (in $/GJ) beyond which any increase would be deemed undesirable by customers.

The benchmark for opportunity losses would be calculated according to the following formula:

$$BPO_t = F_t * \exp(-\alpha_{99} * \sigma_t) - F_t \quad (2)$$

Where: BPO_t is the opportunity loss benchmark for month t, expressed in $/GJ

F_t is the price for the forward contract for month t, expressed in $/GJ,

exp() is the exponential function

α_{99} is the 99th percentile of the standard normal distribution, and

σ_t is the historical volatility of the price logarithm for month t.

The opportunity loss limit would thus be defined as the opportunity loss (in $/GJ) beyond which any loss would be deemed undesirable by customers.

According to the Expert recommendation, the price increase benchmark (BHP) would be calculated as the average of the 12 monthly price increase benchmarks (BHP_t) for the gas year in question, which is November 2013 to October 2014 for the 2014 Rate Application. Similarly, the opportunity loss benchmark (BPO) would be calculated as the average of the

[11] This formula is equivalent to the *LOGNORM.INV* function in MS Excel.

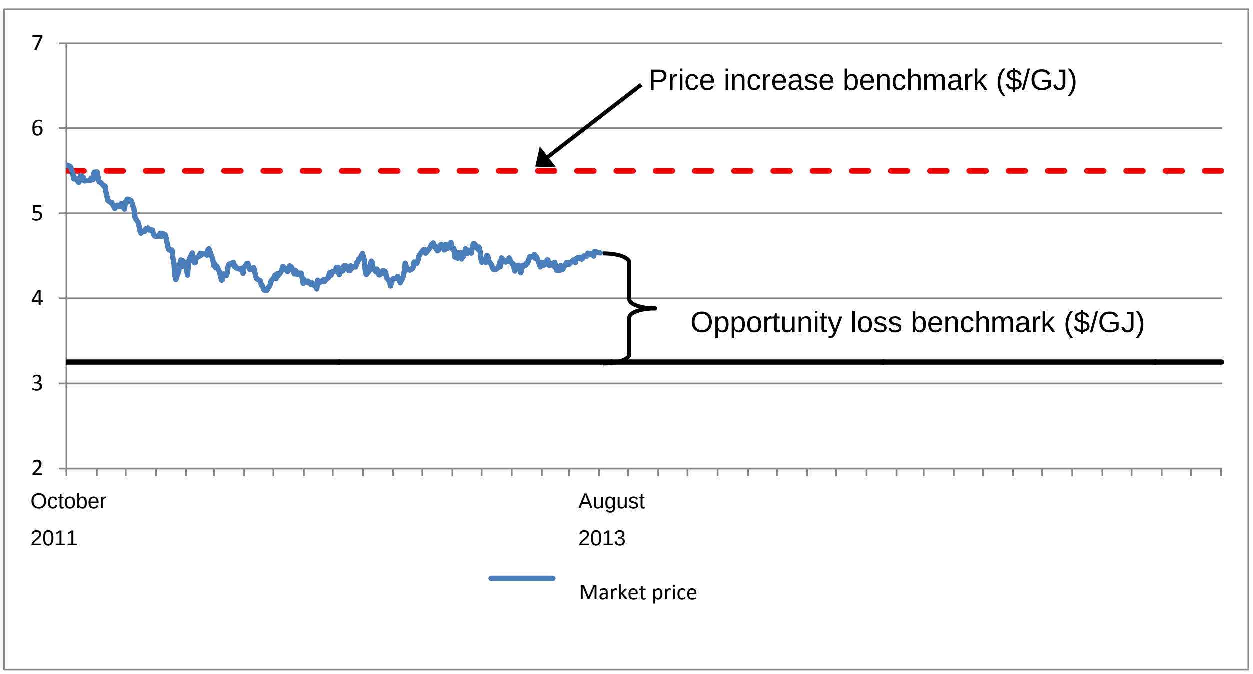
12 monthly opportunity loss benchmarks (BPO_t) for the 12 months of the gas year in question.

Gaz Métro would use these results to determine what would be the maximum price beyond which any additional price increase would be deemed undesirable and the opportunity loss level beyond which any additional opportunity loss would be deemed undesirable. The Program's objectives would then become:

- Main objective: Reduced exposure to price increases above the price increase benchmark
- Underlying objective: Limiting opportunity losses below the opportunity loss benchmark.

The benchmarks proposed for the 2014 fiscal year as well as the detailed calculations are presented in Appendix A. Graph 1 shows the benchmarks.

Graph 1: Examples of Benchmarks



Source: Bloomberg

The benchmarks would be determined once per year by applying the formulas proposed in this section and would be presented to the Régie for approval in conjunction with the Rate Application. The benchmarks thus approved would continue to be applied until the Régie approves new ones.

3.3 Quantitative Assessment of Risks

Once the risks have been identified and the objectives have been quantified, the second step comprises quantitatively measuring the possibility of not attaining these objectives.

3.3.1 Price Increase Risk

The assessment of the price increase risk would be done using the following three steps:

- The estimation of the distribution of natural gas prices for a given month using the log normal price hypothesis
- The calculation of the intrinsic value of the financial derivatives in effect for said month
- The calculation of the likelihood that the price of natural gas, including the effect of the financial derivatives, would exceed the price increase benchmark (BHP).

This risk of overruns would be the risk that is deemed unacceptable and that the use of financial derivatives aims at eliminating. Mathematically, this probability would be expressed as follows:

$$P\left[C_t - \Pi_t\left(C_t\right) < BHP\right] > 95\%$$

Where: C_t is the price paid for month t (unknown), expressed in \$/GJ

$\Pi_t(C_t)$ is the intrinsic value of the financial derivatives (according to price C_t) for the month t, expressed in \$/GJ

BHP is the applicable benchmark, expressed in \$/GJ.

In practice, using the historical volatility of prices and the price log normal assumption, Gaz Métro would first calculate C^{95}_t, the 95th percentile of the price distribution. Gaz Métro would then calculate $\Pi_t(C^{95}_t)$, which is the intrinsic value of all of the financial derivatives in effect if price C^{95}_t came into effect. The undesirable price increase risk (RH) would then be defined according to the following formula:

$$RH_t = C^{95}{}_t - \Pi_t\left(C^{95}{}_t\right) - BHP \qquad (3)$$

Where: RH_t is the price increase risk deemed undesirable for month t, expressed in $/GJ
C^{95}_t is the 95th percentile of the price distribution for month t, expressed in $/GJ
$\Pi_t(C^{95}_t)$ is the intrinsic value of the financial derivatives (according to price C^{95}_t) for month t, expressed in $/GJ
BHP is the applicable benchmark, expressed in $/GJ.

In agreement with the Expert recommendation, the 95th percentile is calculated over a 40-day range, which is the approximate period between evaluations. If the previous equation gives a negative result, RH_t would then be equal to 0.

3.3.2 Opportunity Loss Risk

To take into account the opportunity loss risk, an evaluation of the probability that the financial derivatives would create an opportunity loss greater (in absolute value) than the opportunity loss benchmark (BPO) must be carried out. Mathematically, this probability would be expressed as follows:

$$P\left[\Pi_t\left(C_t\right) > BPO\right] > 95\%$$

Where: $\Pi_t(C_t)$ is the intrinsic value of the financial derivatives (according to price C_t) for the month t, expressed in $/GJ
BPO is the applicable benchmark, expressed in $/GJ.

By using the same normality assumption and the same volatility of price variations as in the previous section, Gaz Métro would calculate C^5_t, the 5th percentile of the price distribution and $\Pi_t(C^5_t)$, which is the intrinsic value of the financial derivatives if price C^5_t occurred. The undesirable opportunity loss risk (RP) would then be defined according to the following formula:

$$RP_t = \Pi_t\left(C^5{}_t\right) - BPO \qquad (4)$$

Where: RP_t is the opportunity loss risk deemed undesirable for month t, expressed in $/GJ

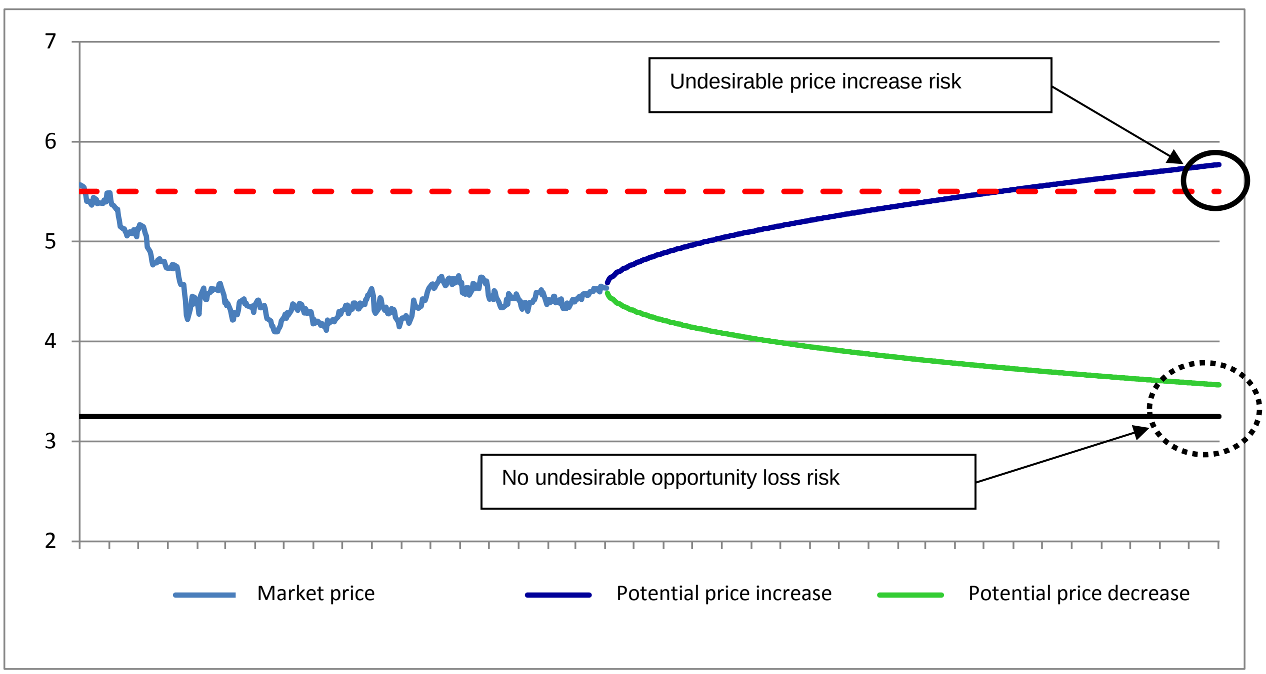
$C^5{}_t$ is the 5^{th} percentile of the price distribution for month t, expressed in $/GJ

$\Pi_t(C^5{}_t)$ is the intrinsic value of the financial derivatives (according to price $C^5{}_t$) for month t, expressed in $/GJ

BPO is the applicable benchmark, expressed in $/GJ.

In agreement with the Expert recommendation, the 5^{th} percentile is calculated over a range that is equal to the term of the month in question. This choice is in line with the fact that financial derivatives contracted in conjunction with the Program would be kept until their expiry. If the previous equation gives a negative result, RP_t would then be equal to 0.

Graph 2: Example of Risk Assessments for January 2015



In the example illustrated in Graph 2, there is the presence of an undesirable price increase risk (RH > 0), because the potential price increase curve including the financial derivatives is above the price increase benchmark (as shown by the solid circle). In the same example, there is, however, no undesirable opportunity loss risk, because the potential opportunity loss curve is above the opportunity loss benchmark (shown by the dotted circle).

3.4 Hedging Strategy

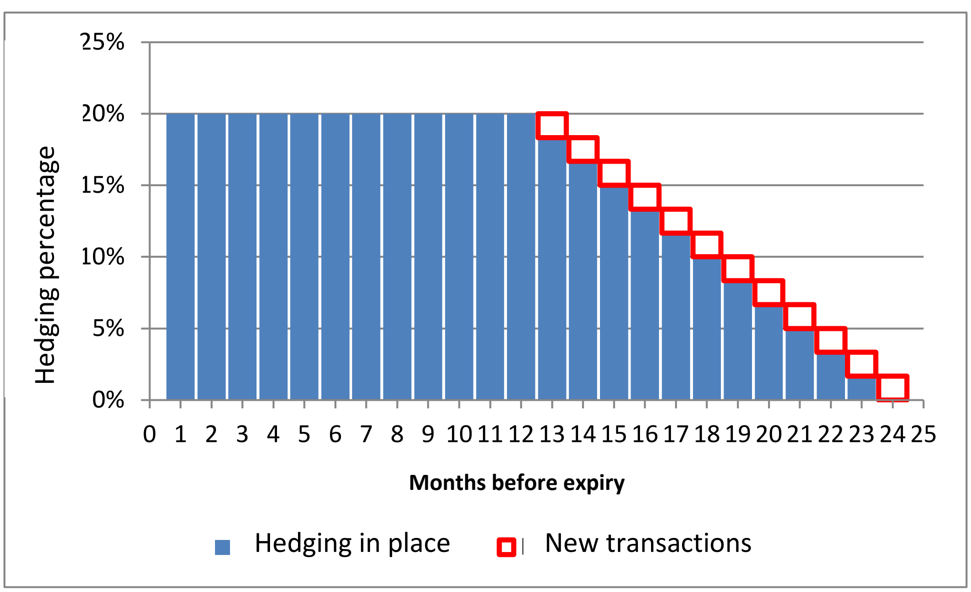
Once the objectives have been quantified and the risks measured, a financial derivatives purchasing strategy would have to be implemented. This strategy would reduce exposure to the risks identified, i.e. which would reduce exposure to undesirable price increases, without however, increasing the risk of undesirable opportunity losses.

3.4.1 <u>Systematic Component</u>

According to the Expert recommendations, the first component would consist of implementing a systematic protection level that is independent of market conditions.

In compliance with the Expert recommendations, Gaz Métro proposes that the systematic component cover 20% of the volume forecast by spreading the purchases over twelve transactions, each representing 1/12th of the objective of 20%. Each month, transactions would be carried out to hedge twelve months starting one year after the current month. As illustrated in Graph 3, by applying this strategy, 20% of natural gas purchases would be hedged one year before their expiration.

Graph 3: Hedging Level of the Systematic Component



In conjunction with the systematic component, Gaz Métro proposes, in line with the Expert recommendations, to use fixed price swap contracts or no-fee collars.

The characteristics of the systematic component would be the following:

- Objective: a hedging level of 20% of the forecast volumes
- Frequency: monthly
- Period: the 13th to 24th month following the current month
- Quantity: Each month, financial derivatives would be contracted to hedge 1/12th of the period's objective.
- Authorized financial derivatives: Fixed price swap contracts and no-fee collars.

This component would allow a hedging amount to be implemented no matter what the market conditions are.

If the estimate of the supply service customer needs is modified, either upwards or downwards, Gaz Métro would recalculate, for each month of the systematic component, the quantity of financial derivatives to be purchased monthly to reach the objective of 20% by spreading the purchases out uniformly over the number of remaining months to attain the objective.

3.4.2 Dynamic Component

Contrary to the systematic component, the dynamic component would be entirely based on the assessments made according to the methodology set forth in Section 3.3. The dynamic component would therefore integrate the natural gas market conditions and the objectives quantified in the hedging decisions, via the RH_t and RP_t terms defined in Section 3.3 (Equations 3 and 4).

$$QH_{t,X} = \frac{RH_t}{X\left(C^{95}{}_t\right)} \text{ and } QP_{t,X} = \frac{RP_t}{X\left(C^{5}{}_t\right)}$$

Where: $QH_{t,X}$ is the quantity, expressed as a %, of the financial derivatives necessary to eliminate exposure to the price increases deemed undesirable for month t.

$QH_{t,X}$ is the maximum quantity, expressed as a %, of the financial derivatives that it would be possible to contract without creating any risk of opportunity loss deemed undesirable, for month t.

RH_t and RP_t are defined according to equations 3 and 4 in Section3.3.

$X(C^{95}_t)$ and $X(C^5_t)$ are the intrinsic values of the financial derivative to be contracted, according to C^5_t and C^{95}_t, expressed in $/GJ.

C^5_t and C^{95}_t are defined according to the assumptions in Section3.3.

Values $QH_{t,X}$ and $QP_{t,X}$ are dependent on the type of financial derivatives chosen, because each type of financial derivative has a different impact on risk exposure.

Based on the Expert recommendations, Gaz Métro would use the following formula to determine the quantity of financial derivative hedges that would comply with both objectives:

$$QH_{t,X} * FIR + (QP_{t,X} - 1) * (1 - FIR)$$

Where: $QH_{t,X}$ is the quantity, expressed as a %, of the financial derivatives necessary to eliminate exposure to the price increases deemed undesirable for month t.

$QP_{t,X}$ is the maximum quantity, expressed as a %, of the financial derivatives that it is possible to contract without creating any risk of opportunity loss deemed undesirable, for month t.

FIR is the materiality factor.

If the previous equation results in a quantity of financial derivatives that is less than or equal to 0, no transaction would be contracted. In accordance with the Expert suggestion, Gaz Métro proposes the use of a materiality factor equal to 60%, which is a factor that grants additional importance to the objective of reducing the price increase risk compared to the objective of reducing the opportunity loss risk. The reduction of the price increase risk being the Program's main objective, Gaz Métro believes, in accordance with the Expert recommendation, that it would be appropriate to give it a greater relative weighting in the hedging decision. In addition, this distribution would take into account the fact that the prices are farther from the average for increases rather than decreases; an element that is taken into account in the log normal distribution used to represent the uncertainty of prices at maturity.

In compliance with the Expert recommendations, Gaz Métro proposes to carry out the evaluations set forth in Section 3.3 eight times per year and to limit financial derivative transactions to 12 months following the current month.

Also in line with the Expert recommendations, for each month, Gaz Métro proposes to limit the quantity of financial derivatives contracted in the dynamic component to 70% of the volumes purchased for the month in question, including the systematic component transactions and the transactions carried out before Decision D-2012-158. Gaz Métro also proposes that there be no minimum quantity to contract in the dynamic component. Within the range from 20% to 70% of the forecasted volume, market conditions would determine the hedging percentage. This volume constraint would limit the risks that the financial derivatives contracted for one month would exceed the volume of natural gas actually purchased during the said month (hedged). In reality, the purchases of natural gas could differ from the forecasts, mainly because of variations in consumption resulting from temperature fluctuations and customer migrations.

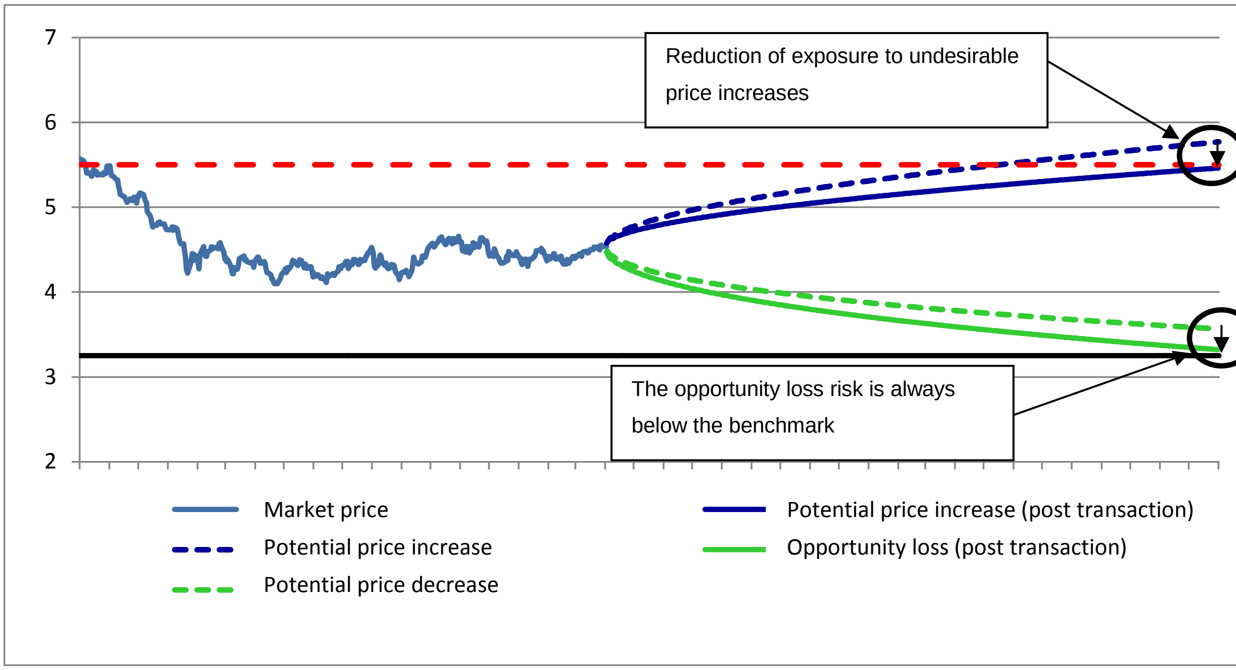
Gaz Métro would use fixed price swaps or no-fee collars in conjunction with this dynamic component. The use of no-fee collars would allow Gaz Métro to choose the exercise price for the collars in order to meet both objectives.

The characteristics of the dynamic component would be the following:

- Objective: reduce the risk of price increases without increasing the opportunity loss risk
- Assessment frequency: at each multi-sector committee, i.e. eight times per year
- Period: the 12-month period following the current month
- Quantity: according to the risk assessment, up to a maximum of 70% of the volumes forecast, including systematic component transactions and the transactions carried out before Decision D-2012-158

1 • Authorized financial derivatives: fixed price swap contracts and no-fee collars.

Graph 4: Application of the Hedging Strategy



4 OPERATIONALIZATION OF THE PROPOSED PROGRAM

4.1 Supply Plan

In actual practice, Gaz Métro's natural gas supply is not all made to the same geographic location. Certain purchases are negotiated up to several months in advance at a price that is based on an index ("index purchases"), while others are at a set price for the next day ("spot purchases"). The gas supply plan submitted with Phase 2 of the 2014 Rate Application proposes purchases of natural gas whose prices are based on indices based on AECO in Alberta, Dawn in Ontario and NYMEX in Louisiana.

4.1.1 Hedging of the Various Purchases

In light of the various types of supply contracts made, Gaz Métro must determine which index should be used for the financial derivatives used to hedge these various purchases.

- Purchases contracted using the NYMEX index: the NYMEX index is the most liquid financial index in North America. For purchases using the NYMEX index, Gaz Métro would therefore use the same index for financial derivatives.
- Purchases contracted using the AECO index: there exists a financial market based on this index. Gaz Métro would therefore use this index to hedge the purchases based on the AECO index.
- Purchases contracted using the Dawn index: the financial market for natural gas in Dawn has very low liquidity. The Expert, in his report, recommends that purchases based in Dawn be hedged by financial derivatives based on the AECO index[12]. Gaz Métro proposes to follow this recommendation and to hedge the purchases contracted in Dawn by financial derivatives based on the AECO index.

[12] Gaz Métro-6, Document 1, Question 59

The following table presents the indices that would be used to hedge the various types of purchases identified in the gas supply strategy.

Table 2: Type of Purchase and Type of Hedging

Indices for physical purchases	Indices for financial derivatives
NYMEX	NYMEX
AECO	AECO
Dawn	AECO

4.1.2 Calculation of Benchmarks and Risk Assessments

Since there will be two distinct indices in the hedging strategy (NYMEX and AECO), Gaz Métro proposes to carry out the calculations in Sections 3.3 and 3.4 for both of the indices. The hedging strategies for the systematic and dynamic components would then be applied separately for each index in function of their respective benchmarks and risk assessments. This strategy of splitting the Program into to "Sub-programs" would make it easier to follow the concepts developed in Section 3 without making the processing more complex.

4.2 Transactions Carried Out before Decision D-2012-158

In compliance with the Expert recommendations, Gaz Métro proposes that the transactions carried out under the former Program parameters be kept. These transactions would contribute to reaching the Program's first objective, which is to reduce the impact of price spikes. The list of these transactions contracted before Decision D-2012-158 is found in Appendix C.

When applying the systematic component, the existing transactions would be taken into account in reaching the 20% hedging objective. New transactions would not be contracted unless the existing transactions do not meet said objective entirely. Table 3 presents the starting dates when the systematic component would take effect, given the transactions already carried out, supposing that all the purchases would be contracted using either the AECO or Dawn indexes.

Table 3: Adjustment of the Systematic Component Based on Existing Transactions

Month hedged	Starting date for the application of the systematic component	Hedging percentage of existing transactions	Adjusted starting date for the application of the systematic component
Nov-14	**Nov-12**	27%	**Completed**
Dec-14	**Dec-12**	18%	**Sept-13**
Jan-15	**Jan-13**	15%	**Sept-13**
Feb-15	**Feb-13**	16%	**Oct-13**
Mar-15	**Mar-13**	17%	**Dec-13**
Apr-15	**Apr-13**	34%	**Completed**
May-15	**May-13**	14%	**Dec-13**
Jun-15	**Jun-13**	16%	**Feb-14**
Jul-15	**Jul-13**	17%	**Apr-14**
Aug-15	**Aug-13**	20%	**Completed**
Sept-15	**Sept-13**	20%	**Completed**
Oct-15	**Oct-13**	13%	**Apr-14**

For the months where the hedging percentage already exceeds the recommended objective of 20%, Gaz Métro would not contract any financial derivative transactions in conjunction with the systematic component.

Of course, the dynamic component would also take into account all transactions contracted before Decision D-2012-158.

5 ANNUAL PERFORMANCE REPORT

In the interviews carried out by the Expert with the customer representatives, the latter mentioned having a hard time understanding how the financial derivatives contracted in the past were used to attain the Program's objectives. Along with the other modifications proposed to its Program, Gaz Métro believes that it would be appropriate to adjust the *Annual Performance Report* to make it more useful in understanding the Program and the effects that the financial derivatives have on the supply price and adapt it to the Program's new parameters.

In this report, Gaz Métro proposes to monitor both of the Program's components to support all the decisions made during the year and all the transactions contracted.

5.1 Monitoring of the Systematic Component

In the monitoring report, Gaz Métro proposes to present, for the fiscal year covered by the report, a table of the transactions contracted each month as well as the percentage of hedging at the end of each month, to clearly show compliance with the parameters that have been approved by the Régie.

5.2 Monitoring of the Dynamic Component

Gaz Métro proposes presenting the results of the risk assessments for each of the dates that the assessments were made, for a total of eight times per year. These data would explain the financial derivative transactions contracted in conjunction with this component or the lack of a transaction.

5.3 Independent Audit

In order to ensure that the Program's parameters are always adapted to the market context and are in line with the Expert recommendations, an analysis to this effect would be carried out by an independent expert every two years.

Gaz Métro emphasizes that the transactions carried out in conjunction with the Program would continue to be presented monthly in the *Supply Service Price Report*.

6 OFFERING MORE THAN ONE SUPPLY PRICE

Gaz Métro proposes that the Program be applicable to all supply service customers.

The possibility of Gaz Métro offering more than one supply service to its customers was the subject of a request for information in conjunction with the 2013 Rate Application[13]. The possibility of "customizing" the supply price based on the customer's risk tolerance level was also mentioned during interviews carried out by the Expert with certain stakeholders[14]. In discussions during the technical meeting held on June 17, 2013, the possibility of giving supply service customers the choice between a service with financial derivatives and another without financial derivatives was also discussed. Gaz Métro believes this alternative, which raises numerous issues at different levels, should not be retained.

6.1 Legal Issues

The purpose of the *Derivatives Act*, L.R.Q., C. I-14.01 (the "LID"), which took effect on February 1st, 2009, is to foster the integrity, equity, effectiveness and transparency of thefinancial derivatives market and to ensure the public's protection against unfair, abusive or fraudulent practices in matters of financial derivatives and market manipulations. It also aims at ensuring the public has access to sufficient, true, and clear information, that is adapted to the knowledge and financial experience of those to whom it is addressed.

After consultation and verification, offering this choice to customers would be similar to offering a financial derivative for the purposes of the LID. This could have the effect of subjecting Gaz Métro to the application of the LID, and specifically to the regulations applicable for registration as a broker (or even a consultant) for financial derivatives, as well as to i) authorization systems for people who create or market financial derivatives and ii) authorization systems for said financial derivative. Compliance with these regulations is very restrictive and would require, for example, and as a condition to the presentation to the Autorité des Marchés Financiers (Financial Markets Authority) of registration and authorization applications, compliance with the following requirements:

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[13] R-3809-2012, 2013 Rate Application, B-0092, Gaz Métro-5, Document 1, Question 25.2.

[14] Gaz Métro-6, Document 1, Appendix D

- Presentation of an application for membership to the Canadian Securities Regulatory Authority ("CSRA")
- Compliance, among others, with very detailed conditions in matters of technical competency for representatives in the field of financial derivatives
- Participation in guarantee funds
- Development of adapted policies and procedures regarding activities in matters of financial derivatives
- The implementation of an operational, financial, compliance and governance framework that must be compliant with LID and CSRA requirements.

These requirements would also have to be complied with continuously afterwards.

Gaz Métro does not have, within its present staff, any employees who have the competencies and who meet the required criteria to qualify as a broker or consultant and deems that it would not be in its customers' best interest to recruit this type of employees and incur all the related costs resulting from being subject to the LID. In Gaz Métro's opinion, the types of activities monitored by the LID are vastly different to Gaz Métro's fundamental business, which is to distribute natural gas.

6.2 Issues regarding Customer Ability to Make an Informed Choice

The Program is an abstract and complex concept and Gaz Métro believes the majority of its supply service customers do not have the required knowledge to easily understand and assimilate the impacts of the choice that would be offered to them and thus to make an informed decision.

This concern about the customers' capability of making an informed choice in a field that is this complex was also brought up by a stakeholder during the interviews carried out by the Expert[15].

The results of the study made by Extract confirmed that Gaz Métro's customers were not aware of the Program. In addition, in this same study, it was observed that the vast majority of

[15] Gaz Métro-6, Document 1, Appendix D, page 122

customers need very detailed explanations in laymen's terms to understand how the Program works. Online visual support and a verbal explanation lasting approximately 10 minutes about the Program were essential, according to Extract, to obtain valid preferences based on a good understanding of the effect of the choices of the various "protection levels" in four market price scenarios. Also, during these interviews, there was never any question about the way Gaz Métro would implement the protection levels. In a context where customers would have to make a choice that would potentially have financial consequences and oblige them to commit themselves for a period of time, they would most likely want more information regarding the complex and more abstract aspects of the Program.

6.3 Labour Issues

The implementation of more than one supply service price by Gaz Métro would require the hiring of additional employees by Gaz Métro to answer calls from customers resulting from this new offer. The number of additional employees would depend on the number and length of the calls that this choice would generate and their distribution over time. At the outset, it is evident that these estimates would be based on the option's communication strategy, the percentage of customers who would take note of said communication and the percentage of customers who, after having taken note, would wish to obtain additional information to make their choice. Gaz Métro does not have any reference base (historical or otherwise) on which it could rely to establish valid and reliable estimates of these parameters.

One of the risks is that Gaz Métro would under-estimate the number and length of calls and/or would incorrectly assess their distribution over time, and that it would not have enough to adequately meet the demand, while being unable to quickly remedy the situation because of the training time required to be able to answer such calls. There could also be slow periods that would mean the additional employees trained specifically to answer these requests from customers not having enough work to fill their days.

In this regard, it is important to note that a significant change in the price of natural gas would most likely result in an increased number of calls because certain customers could question the relevance of their choice. This situation would be greatly amplified if market conditions resulted in significant differences between the prices of both supply services, without forgetting the additional negative effect that could result from any potential media coverage of this type of situation. Gaz Métro absolutely cannot predict these situations in advance.

For example, supposing that 25% of the 170,000 customers admissible for this new service contacted Gaz Métro for more information about the subject and that the calls, which would last for an estimated average of 45 minutes each, came in uniformly over the year, Gaz Métro estimates that it would have to hire 23 new employees to meet the demand during one year.

The estimation of the average length of a call is based on experience during the survey carried out by Extract and on Gaz Métro's experience for the fixed price program. Extract spent an average of 12 minutes on the scenarios, with visual support and by ensuring that the person surveyed had understood sufficiently well that his/her choice would be representative. It should be noted that in the case of the survey, the interview was specifically put together to minimize call time, the interviews were carried out with volunteers and the answer given by the person being surveyed did not commit him/her to anything. Since it would not be a directed discussion like the survey and the information to provide (including migration rules) would be sizeable and complex, Gaz Métro considers 45 minutes to be a reasonable estimate of the average length of each call. This average length is comparable to that of calls regarding the present fixed price program.

The total cost associated with these hirings, and the training of new employees, would vary according to whether the issue addressed in Section 6.1 occurred or not, without taking into account the challenge that this type of hiring would involve.

Finally, it is important to state that in addition to the costs resulting from the new employees, there would be several other elements to consider when implementing the option:

- <u>Establishing a communication strategy</u>: Gaz Métro would have to determine the most efficient communication strategy and develop the information elements (brochure and website)
- <u>Modifications to SAP (including the invoicing module)</u>. Since the option of having a second supply price has not been provided for in SAP, an in-depth analysis of all the impacts would have to be carried out and the solutions implemented.

Gaz Métro has not evaluated the costs of these two elements, deeming that they would not be the main issue in the implementation of this alternative that has been deemed unacceptable by Gaz Métro.

6.4 Issues regarding Migration Conditions

Gaz Métro's customers already have the choice of belonging to the supply service or the fixed price program or being a direct purchase customer. In this context, Gaz Métro has implemented the benchmarks and conditions governing migrations from one service to another. Firstly, these restrictions help to comply with Gaz Métro's operational constraints, and secondly, they prevent customers from changing services simply to experience savings at the expense of Gaz Métro's other customers. Over the years, and in the spirit of fairness toward all customers, these service conditions have been adjusted to meet certain concerns and specific situations that arose.

Therefore, it is reasonable to believe that it would be easier for a customer to change supply services than to migrate toward the fixed price or direct purchase programs, where he must sign a contract with the supplier. To prevent customers from migrating from one service price to another depending on market conditions, Gaz Métro would have to propose new migration conditions to ensure fairness in services in light of this new migration option.

In addition to the questions of fairness between services, without restrictive migration conditions, it would be impossible to forecast the volumes for each of the services and therefore practically impossible for Gaz Métro to contract the financial derivatives required for protection.

Of course, the restrictive conditions implemented to ensure fairness between the services could become irritating, particularly for customers who want to modify their choice of service pursuant to a change that would potentially have no connection to market prices.

The application of service conditions is relatively easy in the case of commercial, industrial and institutional customers. In fact, they often have the resources necessary to assimilate the effect of these service conditions on their gas bills. Gaz Métro submits that this is probably not the case for smaller customers, specifically residential customers.

In addition, considering the type of customers that make up the small-yield customer base, the application of natural gas service conditions could be difficult. In reality, this type of client is much more "mobile" than the others. Presently, each year, Gaz Métro manages a significant number of moves and changes to the person responsible for the account (private individual responsible for the natural gas bill). For each of these events, Gaz Métro will have to question whether or not the service conditions must be applied or not. For example, should migration costs apply in the case of a change in the person responsible for the account, in the case of a change in owner, in the case of sub-leasing, etc.? In spite of all the best judgement Gaz Métro would show, due to the number of customers involved, customers could possibly be dissatisfied and therefore complain, either to the Régie or the courts.

6.5 Issues regarding the Default Option for Customers who do not make a Choice

No matter what communication strategy is used, it is clear that certain customers would not indicate a supply service choice. These customers would, however, have to be registered in one or the other of the options for billing purposes. Gaz Métro would therefore have to determine a "default" option for these customers. However, this choice could have major consequences in the case of extreme changes in the price of natural gas and a customer could feel wronged by the default option, potentially resulting in complaints or even legal proceedings. Taking into consideration the survey findings presented in Section 2.2 in this proof, Gaz Métro is of the opinion that, in this case, the default supply service should absolutely be the one with financial derivatives.

6.6 Customer Dissatisfaction Management Issues

In spite of the good will of all parties involved, it stands to reason that certain customers will be dissatisfied with the choice they made after, for example, a significant price change, and could, in this event, state that the options offered were not clearly explained to them.

This situation occurred during the current fixed price program. Since the *financial derivatives program* is conceptually much more complicated than that for fixed prices, Gaz Métro can foresee, in relative terms, an increase in the number of customers dissatisfied with their choice. If we also take into consideration the number of customers that are likely to be affected by this Program, which is a much higher number than those who signed up to the fixed price program, we can easily see the potential level of dissatisfaction.

This dissatisfaction could also increase due to the restrictive migration conditions that would be implemented to ensure fairness between services (Section 6.4).

For all these reasons, Gaz Métro believes that the best approach for customers is for there to be only one supply price for all supply service customers and that this price include the effects of the *financial derivatives program*, as has been the case since 2001.

7 ALTERNATIVES

As requested by the Régie in its Decision D-2012-158, Gaz Métro has assessed the various alternatives to a financial derivatives program with the aim of offering price stability. In fact, there are several ways to meet this general objective without using financial derivatives. However, none of them can completely replace a financial derivatives program.

7.1 Equal Payment Method

The equal payment method comprises billing a customer for a constant monthly amount over a given period, based on an estimation of his/her annual bill established by using the previous year's consumption and a price forecast. This method completely eliminates billing volatility over a defined and limited period (generally one year). In addition to eliminating any variations due to natural gas market price fluctuations during the period, the equal payment method also eliminates variations resulting from fluctuations in consumption, including the weather.

This method however, does not reduce the impact of an increase in natural gas prices. It only postpones the increase until the end of the equal payment period. The volatility calculated over a longer period than for the equal period method is not absent. In addition, in the case of significant variations from the price forecasts or to the consumption profile, a re-evaluation of the monthly amount to be billed can be made during the year in progress.

This option is already offered to supply service customers.

Gaz Métro considers that the equal payment method does not in any way contribute to protecting customers from price spikes and does not fulfill the objective of reducing volatility except over a short period of time. It purely and simply constitutes a budgetary management tool for customers who desire a stable distribution of their payments during a given year.

7.2 Modification of the Monthly Supply Price Calculation Formula

The current supply price formula partially protects supply service customers by calculating a seasonally-adjusted price (based on an average of the futures prices for the next 12 months) and absorbing the price differences recorded monthly over the next 12 months.

However, the gas price adjustment formula is powerless to prevent price fluctuations in the case of an increase in natural gas prices reflected in the first twelve months of the forward curve. In this case, the customers absorb the entire increase.

The current formula could be modified to reduce the impact of the variations in natural gas prices. We could, for example, absorb the differences over 24 months rather than 12 months, but this type of modification would clearly be in conflict with the principle of intergenerational equity. In fact, the current calculation of the supply price is a compromise between a reduction of volatility and the maintaining of intergenerational equity.

Gaz Métro does not propose any change in the monthly price calculation formula for the supply service because it feels that the existing formula is a good compromise between reducing volatility in the price of natural gas and fairness between current and future customers.

7.3 Extending the Service Offer for the Fixed Price Program by Brokers

Through brokers, Gaz Métro offers a price program through which the customer commits to a given price for a set period (generally between one and five years). The fixed price program allows customers to protect themselves completely against price fluctuations for the period covered by the agreement. This fixed price program, approved by the Régie in its Decision D-2003-180 (2004 Rate Application, R-3510-2003), is offered to customers whose annual consumption is between 7,500 m³ and 1,168,000 m³.

This decision to set the lower limit to 7,500 m³ was a result of arguments made by representatives of small consumers, specifically the UC. In its brief submitted in conjunction with the 2004 Rate Application, the UC recommended that Gaz Métro not be authorized to offer the fixed price program to its residential customers (single-family dwellings, duplexes and triplexes) unless satisfactory legislative or regulatory monitoring was implemented to govern the brokers' work. The UC mentioned that in other provincial jurisdictions, brokers must obtain a permit and often post a bond, which, in addition to guaranteeing the reliability of the company, may be used to compensate consumers in the case of a dispute. The UC recommended that the Régie limit access to the fixed price supply service to customers consuming more than 10,000 m³ per year.

In its Decision D-20013-180 authorizing the implementation of this fixed price program, the Régie thus showed that it was sensitive to the reserves expressed by the representatives of small consumers and specifically excluded customers whose annual consumption is less than 7,500 m³.

The legislative and regulatory framework to which the UC referred has not changed since then.

Based on its experience since the implementation of the fixed price program ten years ago, Gaz Métro believes that it should not be extended to include customers with the lowest consumption. In fact, the current fixed price program is complex and difficult to understand, even for the customers who are currently targeted by it. Gaz Métro doubts that the low-consumption customers have the resources available to make informed decisions on the fixed price supply offer. Moreover, during the interviews carried out by the Expert with customer representatives, the customers' ability to make an informed decision was raised by at least one stakeholder[16].

Gaz Métro feels that it would have to hire between 10 and 15 additional employees to manage the fixed price program if it became accessible to customers with an annual consumption that is below 7,500 m³ and if one quarter of them (25%) took advantage of this option. Gaz Métro believes that extending the current fixed price program to customers with the lowest consumption would cause more harm than good. In addition to the concerns raised during the 2004 Rate Application, which are still valid, it is important to underscore other factors that support the status quo, specifically the scant recourse the smallest customers would have in the case of a dispute with suppliers, the absence of legislative and regulatory supplier monitoring systems, the lack of knowledge by low-consumption customers to make informed decisions on the supply price, and the relevance of Gaz Métro's role in the education of its customers.

Gaz Métro considers that because the natural gas market is unregulated, it should not have to replace said market. Gaz Métro adds that it should not have to play the role of "referee" or "guardian" either. However, in actual fact, that is the role that is conferred on it in the current fixed price program through minimum trade practices. Even though it is presently manageable because of the clients targeted by the fixed price program, Gaz Métro considers that it should

[16] Gaz Métro-6, Document 1, Appendix D, page 122

not be the authority responsible for the application of a fixed price program offered to all of the small yield clients.

Given the above, Gaz Métro considers that it is not desirable to extend the current fixed price program offered by brokers to customers with an annual consumption below 7,500 m^3.

7.4 Use of Storage

As mentioned in the Expert report, storage is the tool that is the most widely used to manage price risk. In fact, storage allows the company to meet its customers' needs in winter using natural gas purchased in the summer, at prices that are generally lower.

Gaz Métro already uses storage in conjunction with its global strategy to supply its clients. In addition to reducing price risk during the winter, storage plays an essential role on an operational level by specifically allowing demand and delivery to be balanced within each day. Certain brokers also use storage in a speculative manner, but that is not the purpose of a regulated distributor.

Gaz Métro already manages storage capacity and submits that storage constitutes a very useful tool in an optimal supply portfolio and that its use is complementary to the Program.

7.5 Fixed Price Supply Contracts

Gaz Métro uses index supply contracts for a portion of the consumption forecast for its supply service. Even though these contracts secure supply, they do not protect against price spikes or reduce volatility because the price paid for the gas is determined by market conditions at the time of delivery. Gaz Métro could choose to negotiate fixed price supply contracts and thus eliminate price uncertainty for the gas purchased. This type of contract could be signed directly with a natural gas producer or with a broker.

From the clients' point of view, this type of purchasing strategy is equivalent to the use of financial derivatives. In reality, this strategy offers the same hedging possibilities as the use of fixed price swap contracts and involves the same issues. However, from the distributor's point of view, this strategy would create an additional level of risk because the transactions would be subject to both the reliability constraint pertaining to the supply and the financial solidity constraint regarding the supplier.

In addition, depending on the quantities considered and the lengths of the contracts, this type of strategy could reduce the supply flexibility of moving purchases from one point to another.

This alternative would not require significant costs to implement.

Considering that this strategy would not provide additional protection when compared to financial derivatives, but would result in higher risks, Gaz Métro would rather maintain the supply decisions separate from hedging decisions.

7.6 Prepaid Supply Contracts

A prepaid supply contract would allow Gaz Métro to pay in advance for a natural gas purchase contract over several years at a price that is lower than the market price at the time the contract is signed. This type of contract could be signed directly with a natural gas producer or with a broker.

The first risk with this alternative would be the credit risk associated with this type of contract. In fact, the transaction is only profitable for Gaz Métro's customers if the counterparty honours its commitments.

In addition, this type of strategy should also be monitored by a program approved by the Régie. Just as with the financial derivatives program, the Régie would certainly want to ensure that the transactions would be made in customers' best interests. In reality, in spite of the discount, it is always possible that future market prices fall below the contract level.

Depending on the quantities considered, this type of strategy would also reduce the supply flexibility of moving purchases from one point to another.

Since these contracts are complex, implementing this alternative would engender costs resulting from the negotiation and preparation of the contracts.

Gaz Métro considers that the risks resulting from the credit quality of the counterparty and said counterparty's capacity to deliver the quantity of gas contracted are important, and, as a result, believes that this alternative is not viable because it could put the customers at risk from a financial point of view.

7.7 Partnership in a Natural Gas Production Unit

Gaz Métro could sign a partnership with a natural gas producer to take possession of the production from a well (or group of wells) in exchange for sharing operating and development costs. With this strategy, the customers would benefit from a cost of gas that would reflect the specific operating costs for a well (or group of wells) rather than market prices.

This activity falls far outside Gaz Métro's field of expertise and would greatly modify its risk profile, which could have negative consequences on Gaz Métro's credit rating. In any event, this alternative could not be implemented without major modifications to Gaz Métro's Partnership Agreement, trust indentures, credit agreement and Note Purchase Agreements with GMi, guaranteed by Gaz Métro because they prohibit Gaz Métro from operating in the oil and gas exploration fields.

Since these contracts are very complex, implementing this alternative would engender costs resulting specifically from the negotiation and preparation of the contracts as well as monitoring of the partnership operations.

Gaz Métro submits that this strategy is not a viable alternative.

CONCLUSION

Based on the elements presented in this proof, Gaz Métro requests that the Régie:

- **Lifts the suspension of the Program**
- **Approves the Expert recommendations**
- **Approves the new Program parameters that could be implemented within a six- to eight-week period following the Régie's decision, including:**
    - **The establishment method for the price increase and opportunity loss benchmarks (Section 3.2.2)**
    - **The parameters for the 2014 fiscal year, as described in Appendix A**
    - **The processing of purchases with different indices (Section 4.1)**
    - **The processing to take into account the financial derivative transactions already in place (Section 4.2)**
    - **The proposal for independent audits every two years (Section 5.3)**
- **Approve the proposed adjustments to the Program's annual performance report.**

Appendix A: Summary of Proposals for the Program

Table 4: Summary of Proposed Parameters for the Program

	Systematic Component	Dynamic Component
Objectives	20%	Hedge only the necessary volumes, up to a maximum of 70% including all transactions
Frequency	Monthly	8 times per year
Period	The 13th to 24th month following the current month	The 1st to 12th month following the current month
Quantity	1/12th of the objective for each month in the period	In function of the risk assessments
Authorized tools	• Fixed price swap contract • No-fee collar	• Fixed price swap contract • No-fee collar
Benchmarks for NYMEX index		• BHP = $4.08 US/MMBtu (maximum price) • BPO = ($0.24) US/MMBtu (maximum loss)
Benchmarks for AECO or Dawn indices		• BHP = $3.63 CAN/GJ (maximum price) • BPO = ($0.29) CAN/GJ (maximum loss)
Relative importance factor		• FIR = 60%

APPENDIX B: Calculations of the Program Benchmarks

Tables 5 and 6 present the calculations used to determine the price increase (BHP) and the opportunity loss benchmarks (BPO) according to the methodology presented in Section 3.2 in this proof.

Table 5: Calculations of the Benchmarks Applicable to NYMEX Index Purchases (in $US/MMBtu)

	Nov-13	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Oct-14**
Closing price on September 6, 2013 (F)	3.62	3.78	3.87	3.87	3.83	3.77	3.79	3.82	3.85	3.87	3.87	3.89
Historical volatility (σ)	3.71%	3.29%	3.13%	3.07%	2.97 %	2.62%	2.55%	2.51%	2.49%	2.48%	2.46%	2.44%
Monthly price increase benchmarks (BHP)	3.94	4.08	4.16	4.15	4.11	4.01	4.02	4.05	4.08	4.10	4.09	4.12
Average	**4.08**											
Monthly opportunity loss benchmarks (BPO)	(0.30)	(0.28)	(0.27)	(0.27)	(0.26)	(0.22)	(0.22)	(0.22)	(0.22)	(0.22)	(0.22)	(0.21)
Average	**(0.24)**											

Table 6: Calculations of the Benchmarks Applicable to AECO Index Purchases and Dawn Index Purchases (in $CAN/GJ))

	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
Closing price on September 6, 2013 (F)	3.11	3.32	3.37	3.37	3.34	3.28	3.29	3.29	3.31	3.32	3.34	3.41
Historical volatility (σ)	4.53%	4.29%	4.08%	4.11%	4.02%	3.81%	3.88%	3.78.%	3.77%	3.73%	3.77%	3.54%
Monthly price increase benchmarks (BHP)	3.45	3.67	3.71	3.71	3.67	3.58	3.60	3.59	3.61	3.62	3.65	3.71
Average	**3.63**											
Monthly opportunity loss benchmarks (BPO)	(0.31)	(0.32)	(0.31)	(0.31)	(0.30)	(0.28)	(0.28)	(0.28)	(0.28)	(0.28)	(0.28)	(0.27)
Average	**(0.29)**											

APPENDIX C: List of Transactions Contracted before Decision D-2012-158

Table 7 presents the fixed price swap contracts contracted before Decision D-2012-158 that are still in effect after November 1st 2013.

Table 7: Fixed Price Swap Contract Transactions in Effect After November 1st, 2013

Transaction date	Hedging period		Quantity *(GJ/day)*	Fixed price *($/GJ)*
	Start	End		
2010-10-15	2013-11-01	2014-04-30	2,500	4.965
2010-10-22	2013-11-01	2014-04-30	2,500	4.85
2010-11-01	2013-11-01	2014-04-30	2,500	4.88
2011-02-08	2013-11-01	2014-04-30	5,000	4.65
2011-02-25	2013-11-01	2014-04-30	2,500	4.58
2011-03-03	2013-11-01	2014-04-30	5,000	4.62
2011-03-08	2013-11-01	2014-04-30	5,000	4.58
2011-03-21	2013-11-01	2014-04-30	5,000	4.80
2011-03-30	2013-11-01	2014-04-30	2,500	4.72
2011-04-07	2013-11-01	2014-04-30	2,500	4.77
2011-04-13	2013-11-01	2014-04-30	2,500	4.745
2011-05-17	2013-11-01	2014-04-30	2,500	4.79
2011-06-03	2013-11-01	2014-04-30	2,500	4.825
2011-06-13	2013-11-01	2014-04-30	2,500	4.745
2011-07-19	2013-11-01	2014-04-30	2,500	4.59
2011-07-20	2013-11-01	2014-04-30	2,500	4.545

1 Table 8 presents the collars contracted before Decision D-2012-158 that are still in effect after
2 November 1st 2013.

Table 8: Collar Transactions in Effect After November 1st, 2013

Transaction date	Hedging period		Quantity *(GJ/day)*	Price floor *($/GJ)*	Price cap *($/GJ)*
	Start	End			
2010-10-15	2014-05-01	2014-10-31	2,500	3.75	6.50
2011-04-06	2014-05-01	2014-10-31	2,500	4.04	6.00
2011-06-22	2013-11-01	2014-04-30	2,500	4.13	5.50
2011-06-23	2014-05-01	2014-10-31	2,500	3.90	5.50
2011-07-20	2014-05-01	2014-10-31	2,500	3.69	5.50
2011-08-04	2013-11-01	2014-04-30	2,500	3.99	5.50
2011-08-29	2013-11-01	2014-04-30	2,500	3.95	5.50
2011-09-15	2013-11-01	2014-04-30	2,500	3.95	5.50
2011-10-13	2013-12-01	2014-04-30	2,500	3.83	5.50
2011-10-26	2013-12-01	2014-04-30	2,500	3.75	5.50
2011-11-04	2014-05-01	2014-10-31	2,500	3.61	5.50
2011-11-07	2013-12-01	2014-04-30	2,500	3.70	5.50
2011-11-11	2014-11-01	2015-04-30	2,500	4.10	5.50
2011-11-28	2014-11-01	2015-04-30	2,500	3.97	5.50
2011-11-30	2013-12-01	2014-04-30	2,500	3.65	5.50
2011-12-01	2015-05-01	2015-10-31	2,500	3.79	5.50
2011-12-05	2014-11-01	2015-04-30	2,500	3.95	5.50
2011-12-05	2013-12-01	2014-04-30	2,500	3.54	5.50
2011-12-07	2014-11-01	2015-04-30	2,500	3.90	5.50
2012-01-06	2014-11-01	2015-04-30	2,500	3.70	5.00
2012-01-06	2013-12-01	2014-04-30	5,000	3.235	5.00
2012-01-10	2014-11-01	2015-04-30	2,500	3.70	5.00
2012-01-17	2014-11-01	2015-04-30	2,500	3.39	5.50
2012-01-17	2015-05-01	2015-10-31	2,500	3.29	5.50
2012-01-17	2013-12-01	2014-04-30	2,500	2.71	5.50
2012-01-17	2014-05-01	2014-10-31	2,500	2.74	5.50
2012-01-31	2014-11-01	2015-04-30	2,500	2.72	5.50

Transaction date	**Hedging period**		**Quantity** *(GJ/day)*	**Price floor** *($/GJ)*	**Price cap** *($/GJ)*
	Start	**End**			
2012-02-17	2014-11-01	2015-04-30	2,500	3.19	5.00
2012-02-24	2013-12-01	2014-04-30	5,000	3.05	4.50
2012-03-02	2015-05-01	2015-10-31	2,500	3.18	4.50
2012-03-02	2013-12-01	2014-04-30	2,500	2.68	4.50
2012-03-02	2014-05-01	2014-10-31	2,500	2.63	4.50
2012-03-02	2014-11-01	2015-04-30	2,500	3.23	4.50
2012-03-07	2013-12-01	2014-04-30	2,500	2.58	4.50
2012-03-07	2014-11-01	2015-04-30	2,500	3.11	4.50
2012-04-12	2014-11-01	2015-04-30	2,500	3.18	4.50
2012-04-13	2013-12-01	2014-04-30	2,500	2.60	4.50
2012-04-17	2013-12-01	2014-04-30	2,500	2.55	4.50
2012-04-17	2014-11-01	2015-04-30	2,500	3.02	4.50
2012-04-20	2014-11-01	2015-04-30	2,500	2.94	4.50
2012-05-10	2014-05-01	2014-10-31	2,500	2.85	4.50
2012-05-10	2015-05-01	2015-10-31	2,500	3.25	4.50
2012-05-11	2013-12-01	2014-04-30	2,500	2.98	4.50
2012-05-14	2013-12-01	2014-04-30	2,500	2.90	4.50
2012-05-23	2014-11-01	2015-04-30	2,500	3.39	4.50
2012-05-24	2013-12-01	2014-04-30	2,500	2.89	4.50
2012-05-29	2013-12-01	2014-04-30	2,500	2.80	4.50
2012-05-30	2014-11-01	2015-04-30	2,500	3.30	4.50
2012-06-06	2014-11-01	2015-04-30	2,500	3.29	4.50
2012-06-13	2014-11-01	2015-04-30	2,500	3.20	4.50
2012-07-06	2013-12-01	2014-03-31	2,500	3.05	4.50
2012-07-06	2013-12-01	2014-03-31	2,500	2.975	4.50
2012-07-06	2014-11-01	2015-10-31	2,500	3.25	4.50
2012-07-16	2013-12-01	2014-03-31	2,500	3.00	4.50
2012-07-26	2013-12-01	2014-03-31	2,500	3.01	4.50
2012-07-26	2013-12-01	2014-03-31	2,500	3.09	4.50
2012-07-27	2014-05-01	2014-10-31	2,500	3.01	4.50
2012-07-27	2014-11-01	2015-04-30	2,500	3.53	4.50

Transaction date	Hedging period		Quantity *(GJ/day)*	Price floor *($/GJ)*	Price cap *($/GJ)*
	Start	End			
2012-08-02	2013-12-01	2014-03-31	2,500	2.925	4.50
2012-08-02	2014-11-01	2015-04-30	2,500	3.36	4.50
2012-08-03	2013-12-01	2014-03-31	2,500	2.85	4.50
2012-08-03	2014-11-01	2015-04-30	2,500	3.30	4.50
2012-08-14	2013-12-01	2014-03-31	2,500	2.77	4.50
2012-08-14	2014-11-01	2015-04-30	2,500	3.15	4.50
2012-08-20	2013-12-01	2014-03-31	2,500	2.75	4.50
2012-08-27	2014-11-01	2015-04-30	2,500	3.13	4.50
2012-08-30	2013-12-01	2014-03-31	2,500	2.68	4.50
2012-09-06	2013-12-01	2014-03-31	2,500	2.64	4.50
2012-09-07	2014-11-01	2015-10-31	2,500	2.97	4.50
2012-09-07	2014-05-01	2014-10-31	2 500	2.48	4.50

APPENDIX D: Analysis of the Survey Made by Extract

Appendix I

CONCENTRIC'S ASSESSMENT OF GAZ METRO'S FINANCIAL DERIVATIVES PROGRAM

CONCENTRIC'S ASSESSMENT OF GAZ MÉTRO'S FINANCIAL DERIVATIVES PROGRAM

TECHNICAL ANALYSIS OF RUBEN MORENO

September 26, 2013

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TECHNICAL ANALYSIS OF RUBEN MORENO

I. INTRODUCTION AND BACKGROUND

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Ruben Moreno. My business address is 1130 Connecticut Avenue NW, Suite 850, Washington, DC 20036.

Q2. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A2. I am Assistant Vice President of Concentric Energy Advisors, Inc. ("Concentric"). Concentric is a management consulting firm specializing in financial and economic services to the energy industry.

Q3. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EXPERIENCE.

A3. I have more than fourteen years of experience in the North American energy industry and an additional 6 years as a management consultant for the manufacturing and service industries in North America. Prior to Concentric, I served as Senior Director for Risk Management for R.W. Beck/SAIC and as Executive Director for Risk Management for Pace Global Energy Risk Management, LLC. As an energy risk management professional I have designed, implemented, audited or acted as an outsourced risk manager for 40,000 MW of load serving generation and the associated fuels. Representative historical clients include Nova Scotia Power, New York Power Authority, Metropolitan Transportation Authority of New York, Powerex, Santee Cooper, Abitibi, Weyerhaeuser, Alcoa and the Guam Power Authority ("GPA"). A copy of my résumé grouped by representative expertise is included as Attachment A.

Q4. PLEASE DESCRIBE YOUR EXPERIENCE REGARDING ENERGY RISK MANAGEMENT.

A4. I have a significant amount of experience addressing energy risk management matters in North America, including supporting risk management needs for Canadian power producers/marketers (such as BC Hydro/Powerex) and end users (such as Weyerhaeuser and Abitibi). I have provided risk management consulting services to regulated utilities, independent power producers and energy developers. The consulting services I have provided address a wide variety of fuels and generation technologies (combined cycle, cogeneration, compressed air, run of the river hydro, cascading hydro, pumped hydro, wind and biomass).

As part of those engagements, I designed, implemented, enhanced, reviewed or audited entire risk management functions on behalf of the client company or on behalf of an external stakeholder. I have also been involved in designing and implementing trading strategies within the boundaries of a risk management program. As a consultant, I advise my clients on the execution of hedging and trading strategies across the full spectrum of these activities. I have provided expert witness testimony on energy risk management and am currently working on behalf of Nova Scotia Power Inc. in designing and implementing a hedging strategy for natural gas.

Q5. PLEASE DESCRIBE CONCENTRIC'S ACTIVITIES IN ENERGY AND UTILITY ENGAGEMENTS.

A5. Concentric provides financial and economic advisory services to energy and utility clients across North America. Our regulatory services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting, resource planning, and energy contract negotiations. Our financial advisory activities include both buy and sell side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; risk management; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

II. SCOPE AND PURPOSE OF TESTIMONY

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A6. Concentric has been engaged by Gaz Métro to evaluate its current hedging program and to produce a report aimed at answering the various concerns expressed by the Régie de l'énergie du Quebec (the "Régie") in its decision D-2012-158, regarding the continued operation of Gaz Métro's financial derivatives program (the "Program"). In its decision, the Régie ordered the Company to

1. Present an assessment of its financial derivatives program prepared by an external expert, that would include an examination of the following: the costs and benefits of the current financial derivatives program for customers; the advantages and disadvantages of maintaining a financial derivatives program; whether it is appropriate to terminate the program; the guidelines for an eventual reformulated program taking into account the current context for natural gas prices; the handling of migrations between direct purchase services and system gas; a benchmarking study examining the use of financial derivatives in the North American energy utility sector; and recommendations as to best practices for managing financial derivatives; and
2. Present Gaz Métro's proposal for the maintenance, reformulation or suspension of the program in a technical meeting. Concentric has developed an assessment of Gaz Métro's financial derivatives program and has presented the results of its assessment to the Régie's staff and the interveners.

Q7. WHAT ARE YOUR CONCLUSIONS REGARDING GAZ MÉTRO'S FINANCIAL DERIVATIVES PROGRAM?

A7. In general, there is no evidence to suggest that Gaz Métro has performed outside the authorized guidelines of the Program, but there are aspects of the Program that could be improved by managing the exposure to opportunity loss that has been prevalent over the past four years. At present, the Program is designed to incrementally hedge the price of natural gas, and the dominant criteria for placing the hedges is time. A Program like this one will prescriptively do well in a rising market, will perform as well as the market in average conditions, and will perform poorly in a market with decreasing prices. Our conclusions are as follows:

1. Among interveners interviewed there is a lack of clarity regarding what the Program is, what it is trying to do, how it is trying to achieve its objectives, and how to measure performance;

2. Over the past four years, the Program has produced prices that compare unfavorably to the strategy of not hedging. This opportunity cost has resulted from hedges performing poorly against settlement prices (an unknown at the time of the hedge), but not due to an up-front premium paid to mitigate price risk;
3. The objectives of the Program lack the necessary specificity to evaluate performance against Program objectives;
4. In my opinion, the Program should not be terminated, but there are elements that need to be improved. I believe this perspective is shared amongst the interveners we interviewed; to my knowledge, none of them indicate a desire to terminate the Program;
5. Comparing the hedged price with the settlement price is not an effective metric to guide the implementation of the Program. The settlement price is an unknown target at the time the hedging decisions need to be made;
6. The Program provides for systematic hedging at established time intervals for a targeted hedge quantity. The opportunity cost of the Program is based on a comparison of the hedged price versus the last price traded (settlement price);
7. Natural gas costs are fully recovered through rates and Gaz Métro does not benefit from hedging activities;
8. The Program has benefited consumers by reducing the volatility of prices, but this benefit has been overwhelmed by the unfavorable hedged price;
9. The enhancements to the Program are based on three basic principles: awareness, measurement of risk, and a decision making process that avoids undesirable risk exposure;
10. The primary enhancement to the Program I recommend is to base hedging decisions on risk exposure with hedged volumes at a quantity sufficient to avoid an undesirable risk exposure. The current Program does not show evidence that it is centered on awareness, measurement of risk, and avoidance of undesirable risk exposures;
11. The enhancements to the Program also include more transparent documentation of how decisions are made and metrics for performance measurement. Measuring

the performance of the Program solely on the opportunity cost sends the wrong incentive to “beat the market”, which is a speculative perspective and not a recommended objective of the Program;

12. It is true that natural gas prices and volatility have decreased over the past four years, but this should not be viewed as a signal that the risk of natural gas markets has diminished. Current market conditions favor the recommended improvements and continuation of the Program;
13. A reformulated Program should prescribe hedging activities that are focused on the avoidance of undesirable risks. It may be that the Program may indicate limited hedging activity based on a balanced approach of upside and downside risk exposure. The decision to avoid hedging based on balanced risk is very different from avoiding hedging altogether; and
14. It is my understanding that Gaz Métro is interested in continuing the Program to manage price exposure on behalf of its customers, and I believe Gaz Métro is properly positioned to do so.

Q8. WHAT IS HEDGING?

A8. Hedging is a series of management decisions aimed at reducing the probability of unfavorable outcomes, typically in the form of undesirable prices and/or volatility. In the case of natural gas prices, hedging is the set of management decisions taken to mitigate the impact on customers of price increases/decreases that may create a wide disparity in the cost of gas from month-to-month, or year-to-year.

Price increases are undesirable because they directly raise rates for customers. Price decreases may also negatively affect customers if prices hedged are higher than the settlement prices. Volatility in itself is undesirable because it curtails the ability to plan expenditures and it may divert consumer spending from other areas.

Q9. WHY DO UTILITIES HEDGE?

A9. Utilities hedge to help stabilize rates and provide competitive prices to consumers. Most LDCs hedge their gas supply needs to alleviate the concern that gas costs may rise and cause a sharp increase in rates that may cause economic hardship for customers. In its simplest form, the utility that wants to create natural gas price certainty may contract with a natural gas producer that wishes to create revenue certainty. In this simple construct the utility and the producer may engage in a fixed-price financial instrument (such as a future or forward) where both get what they were looking for: a known cost and known revenue. The price of the commodity for future delivery will continue to fluctuate until the financial instrument expires (a few days before the contracted month starts), but these two counterparts have locked-in their economics in advance.

On a daily basis, the utility makes an explicit decision to either lockthe price today or wait for some other day to fix the price, or simply wait until the financial instrument expires and buy the commodity at spot. This decision involves uncertainty (i.e. risk) because it is a comparison of a known price today (the futures price) versus an uncertain price tomorrow or at settlement. The price may be better if the utility waits, but then again it may not.

Regulated natural gas LDCs have regulatory cost recovery mechanisms for gas costs, including the costs associated with hedging activity. The ability to pass on those costs to customers is dependent on those costs being determined as reasonable and prudent in the context of approved hedging guidelines. Companies engaged in hedging (including utilities) often find themselves in the unfortunate position of being darned if they do (if hedged price exceeds market prices at expiration); and darned if they don’t (when market prices increase and there is no hedge to mitigate the impact). This creates an asymmetric prudence risk for utilities, i.e. there is no direct benefit to the utility to hedge other than to avoid the risk of a negative prudence determination related to its hedging activities or lack thereof. This is the primary motivating force leading utilities to pursue hedging.

Q10. IF UTILITIES HAVE GAS COST PASS THROUGH MECHANISMS, WHY IS HEDGING IMPORTANT FOR A UTILITY?

A10. Hedging provides a valuable service to the customers under a fixed set of rules, since there are circumstances when the right thing to do is simply not to hedge. If we agree that a reduction in volatility and certainty in the cost structure is desirable, then somebody needs to provide this protection to customers. Unless the customer is large and sophisticated, it typically would not have the financial wherewithal to independently pursue hedging; and the regulator does not have the mandate to provide this certainty. Even though the utility will not financially benefit from the Program, it is in the best position of the three primary stakeholders (customer, regulator and utility) to hedge the price on behalf of the customer.

Q11. PLEASE DESCRIBE GAZ MÉTRO'S HEDGING PROGRAM

A11. Gaz Métro's hedging program was established in 2001 (D-2001-2014) pursuant to an application by Gaz Métro and approved by the Régie de l'énergie (the "Régie"). Gaz Métro has since applied the Program according to the parameters approved by the Régie each year and has modified its application according to the market context.

The objectives of the hedging program are:

- Stabilizing the cost of natural gas by reducing portfolio volatility;
- Limiting the impact of potential price increases during increase cycles or during peak periods of demand on the market; and
- Seizing what is perceived to be a market opportunity in order to preserve the competitive position of natural gas.

Gaz Métro has developed a programmatic system for hedging where it determines the annual volume to hedge four years into the future by applying a hedge percentage to the estimated load forecast (which incorporates a 10% annual customer migration).The hedge percentage may range from 20% to 75% in year 1, from 0% to 75% in year 2, and declines by a factor of 0.75 for each succeeding year. In any given month, Gaz Métro is not allowed to trade more than 1/6 of the maximum hedge percentage for the year.

Maximum strike prices for swaps and put options are established to maintain parity with electric bills for a majority of commercial customers. The most recent Program, proposed in Gaz Métro's 2013 rate case, set the maximum strike price at $8.15 per GJ such that 91% of commercial system gas users would be competitive with electricity.

For the first year, the maximum strike price for purchased call options is based on futures curves and judgement in the near year. For the later years, the strike price is indexed using the forward curve at the time of rate case preparation.

In order to ensure compliance with the parameters approved by the Régie, as well as to make strategy decisions on volumes to hedge and the type of tools to use, a multisectorial committee was established to develop guidelines for hedging activities. An operational group conducts hedging in accordance with the procedural guidelines set by the multisector committee; all risk management activities are reviewed quarterly by Gaz Métro's audit committee for compliance with limits approved by the Régie.

Q12. PLEASE DESCRIBE THE NATURE OF YOUR REVIEW OF THE PROGRAM.

A12. I focused on the elements enumerated in the Régie's decision D-2012-158, examining Gaz Métro's Program to provide an assessment of the following: the costs and benefits of the Program for customers; the advantages and disadvantages of maintaining a Program; whether it is appropriate to terminate the Program; the guidelines for an eventual reformulated Program, taking into account the current context for natural gas prices; the handling of migrations between direct purchase services and system gas; the benchmarking study of the use of financial derivatives in the North American energy utility sector; and recommendations as to best practices for managing financial derivatives.

In conducting these analyses, Concentric canvassed North American utility hedging best practices literature and programs to ascertain what the current practices are among gas LDCs and what is considered to be best practices. We also conducted stakeholder interviews to gain information on Gaz Métro's customers' preferences and perspectives on price changes and volatility. These interviews informed Concentric's view of the risk sensitivities of customers. In addition, we reviewed the costs and benefits of the Program using the existing definition of cost and benefit adapted to take into consideration Gaz Métro's operational restrictions. The results of these analyses are represented in this technical analysis.

III. BENCHMARKING

Q13. PLEASE EXPLAIN HOW YOU HAVE CONDUCTED YOUR BENCHMARKING STUDY.

A13. Based on prior assignments and publicly available information, we selected North American gas LDC's hedging programs for which we had hedging plans either readily available or easily accessible and have extracted information on the following topics: risk management governance, objectives, hedging protocols (including strategies, hedging instruments, hedge horizon), performance metrics, processes for risk monitoring and assessment, and risk reporting. We detailed our understanding of the programs and summarized them in Appendix B. Some of the information is purposefully redacted for confidentiality issues.

Q14. WHAT KNOWLEDGE IS TO BE GAINED FROM THE RESULTS OF THE BENCHMARKING STUDY?

A14. The benchmarking study helps us understand how other regulators are approaching this topic and how utilities are implementing hedging. The Régie has expressed a concern that Gaz Métro's Program may require more active management in terms of the selection of tools, hedge horizon and hedge volume and greater consideration of prevailing market trends and context. In that vein, the Régie asked to have a perspective of best practices for managing financial derivatives programs and a perspective of how other North

American gas utilities are structuring their programs to manage the current challenges of the natural gas market.[1]

The sampling of the companies selected for the benchmark was based on available information to us, and while it doesn't necessarily represent a statistically-significant sample, the companies referenced share a common concern to protect the consumer against price increases while at the same time remaining competitive and avoiding excessive downside risk exposure. In the article "Hedging Under Scrutiny"[2] written by staff from Concentric, we establish how regulators of these companies are scrutinizing the structure and performance of these programs, and how these companies are responding and adapting to these inquiries.

Q15. HOW ARE ENERGY COMPANIES IN NORTH AMERICA APPROACHING HEDGING?

A15. Most LDCs hedge a material portion of their supply needs, and there is a fair degree of uniformity in hedging strategies. A survey by the AGA published in July 2012 indicated that of 63 local gas utilities with service territories in 37 states, 81% of them used financial derivatives to hedge at least a portion of their supply (Appendix D).[3]

According to this study, the typical gas LDC manages its hedging program as follows:

1. Use all available storage to cover as much of the winter peak requirement as possible, i.e. one quarter to one third of winter peak needs, priced to customers at the WACOG plus demand charges for storage;
2. Hedge much of the remaining winter base-load requirement via forward purchases made in regular installments beginning a year or so ahead of the delivery period; and

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1 Régie decision #D-2012-158, R-3809-2012 (November 23, 2012)

2 Ryan, Julie and Julie Lieberman. (2012). Hedging Under Scrutiny: Planning Ahead in a Low-cost Gas Market. Public Utilities Fortnightly. February. Pp. 12-19.

3 American Gas Association. Energy Analysis: LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season (July 31, 2012).

3. Leave the more uncertain, non-baseload, non-storage quantities unhedged, to be procured on a monthly or daily basis at prevailing spot prices.

By leaving some supply open and unhedged, there is assurance that customer prices will directionally match upstream wholesale price changes and by hedging winter baseload via regularly-scheduled installment purchases, no efforts are made to time the market. Some use options or collars to manage their risk within a bracketed range, thereby capping upside costs and leaving downside costs partially open. Some use accelerators and decelerators to adjust the timing and size of their installment purchases if market conditions meet established criteria. Lastly, it is fairly uncommon for utilities to use formal measures of risk reduction to monitor, control, and evaluate hedging, such as Value at Risk (VaR) measures and simulation models.[4]

Q16. WHAT IS THE STATUS OF FINANCIAL DERIVATIVES PROGRAMS TO MANAGE COMMODITY PRICE RISK AMONG CANADIAN GAS LDCS?

A16. Currently, the only Canadian province that has an active hedging program approved by a regulator is Sasketchewan. In Alberta, gas distribution companies do not have a sales function other than default service, and as a result, do not engage in hedging. In Ontario, the primary natural gas utilities' hedging programs were cancelled by the Ontario Energy Board (OEB) in 2007 and 2008 in favor of a quarterly rate adjustment and equal billing plan, which the OEB determined would collectively provide sufficient rate smoothing effects such that hedging would be unnecessary. In Manitoba, the utility only engages in hedging to support its fixed rate programs, and has been ordered to cease any hedging associated with its variable rate offerings. In British Columbia, Fortis BC was recently denied its application for a revised hedging program G−120−11 (July 2011) on the basis

[4] Value at risk, or VaR, is a means of measuring the amount of financial risk present in a specific commodity and was originally developed to address the risk of stocks, foreign exchange and interest rates. There are two main components used to determine the value at risk. First, the time period to be considered is established. This may be a day, a month, or even a year. Next, the overall confidence level of the predictions must be ascertained; this typically requires market research and analysis of historic performance data. Typically confidence levels are set at either 95% or 99% probability. Value at risk calculations are intended to provide an overview of likely risk scenarios for hedging portfolios.

that although moderation of natural gas price volatility to stabilize customer rates was a worthy goal, the BCUC did not find evidence to suggest that the proposed hedging program provided the most cost−effective approach or solution to the issue. Fortis's hedging program was rejected with the exception of procuring basis swaps to protect the Sumas-AECO basis differential, citing the lack of rigorous analysis supporting its hedging proposal and the past cost associated with the program.

Q17. WHY ARE UTILITY HEDGING PROGRAMS UNDERGOING INCREASED REGULATORY SCRUTINY?

A17. After a decade of natural gas price volatility it appears we have entered a new and markedly different environment of new supply and lower volatility in natural gas markets. This surplus has resulted from plentiful shale gas, excess LNG capacity, winters that have been consistently warmer than normal, a down economy, and declining average use of natural gas by consumers. It has become apparent that hedging programs based on time-trigger designed during highly volatile, rising price environments may not be well-suited when downside exposure is a significant preoccupation of stakeholders. Hedging programs in Canada were all dominated by a time-trigger mechanism.

Hedging strategies that execute hedges based on time triggers will generate high opportunity costs when prices fall. This is particularly true of those hedging programs that follow a structured procurement process where hedges are acquired based on a pre-determined calendar, pre-determined budget or pre-determined target levels. In the context of falling prices and reduced volatilities, these programs have accumulated significant opportunity losses (hedges placed through physical contracts) or negative hedge settlements (hedges placed through financial counterparts). The critical flaw of a program that is largely driven by calendar triggers is that it hedges to avoid an "intuitive" pattern of prices increasing, but it ignores the possibility that prices will decrease. It is precisely this risk of prices decreasing that is at the heart of increased regulatory scrutiny.

A recent AGA survey confirms that where at one point 92% of regulators supported hedging programs by their regulated natural gas utilities, only 81% of utility respondents were hedging for the winter of 2011-2012[5]. The problem that utilities face is, when compared to spot prices over the past years, hedging has provided a cost of gas that is well in excess of that which could have been purchased at spot. Indeed, Gaz Métro reports that the Company incurred opportunity costs stemming from the Program of $108 million for 2012 alone. The Régie has expressed concern that Gaz Métro's Program (in its current form) may not provide the least cost solution for system gas users.[6]

Q18. HOW DO THE CONCERNS FROM THE RÉGIE COMPARE TO CONCERNS FROM REGULATORS IN OTHER JURISDICTIONS?

A18. The concerns from the Régie are similar to those of regulators in other jurisdictions in Canada and the United States. Since programs that were structured around time-triggers made no explicit recognition of downside risk exposure, the prices achieved through the hedging programs have compared unfavorably against the alternative strategy of "not hedging". In a recent article by Concentric[7], we highlight that regulatory commissions and interveners are challenging the merits of their utilities' hedging programs with increasing frequency, questioning whether the risk mitigation benefits of hedging have justified the associated costs, and whether customers are paying too much to manage a risk that might no longer exist.

The concerns expressed by the Régie in its decision D-2012-158 are in alignment with concerns across the industry. Taking into account the current natural gas market environment and the opportunity cost incurred by system gas users, the Régie ordered

[5] American Gas Association. Energy Analysis: LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season (July 31, 2012).

[6] Régie's decision #D-2012-158, R-3809-2012, November 23, 2012

[7] Ryan, Julie and Julie Lieberman. (2012). Hedging Under Scrutiny: Planning Ahead in a Low-cost Gas Market. Public Utilities Fortnightly. February. Pp. 12-19.

Gaz Métro to suspend hedging, present an assessment of the Program and submit a proposal for a reformulated Program.

The shift toward reassessing hedging practices is relatively recent, but the trend for further scrutiny is clear. In some instances, hedging programs have continued without modification, while in other cases hedging programs have been targeted for additional review. Take for instance another recent ruling from the District of Columbia Public Service Commission that determined that the LDC (Washington Gas Light Company) should be allowed to continue its hedging strategy.[8]

In 2008, a survey conducted by the National Regulatory Research Institute (NRRI) indicated that most commissions in the U.S. either supported or were neutral to hedging[9]. This was reinforced in a follow-up survey the AGA conducted in 2009[10]. Among more than 100 respondents, over 90% said their commissions allowed financial hedging of commodity price risk. However, only a very small number of commissions required utilities to engage in financial hedging.

Q19. WHAT ARE THE PRIMARY CONSIDERATIONS OF REGULATORS IN TERMS OF PRICE RISK AND ITS IMPACT ON CUSTOMERS?

A19. Generally regulators are concerned if gas costs deviate so sharply from previous levels that it causes economic hardship for customers, or if any increases in gas costs resulted from indifference to hedging that might have buffered some of the variance. Similarly, regulators are concerned if falling gas market prices are not reflected in rates. Either scenario may provide the basis for a prudence disallowance if the execution of the

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[8] Public Service Commission of the District of Columbia GT 01-1-199 (May 10, 2013). http://www.dcpsc.org/pdf_files/commorders/orderpdf/orderno_17130_GT01-1.pdf

[9] National Regulatory Research Institute, *NRRI Services: Survey on State Commission and Local Gas Distribution Company Actions in Addressing High Natural Gas Prices,* (July 3, 2008).

[10] Bruce McDowell, *AGA Rate Inquiry: Regulatory Hedging Policies*, American Gas Association, (Fall 2009).

strategy was outside of the authorized decision process. How the hedged price compares against the ultimate spot price (an unknown when the hedging activity took place) should never be the basis for prudence disallowance.

According to the 2012 AGA Survey, when asked about regulatory focus, 35 of 56 gas LDCs believe the regulator is equally interested in both low gas prices and the stability of gas prices, 12 LDCs indicated the regulator is only interested in the lowest price, while 9 LDCs indicated the regulator is only interested in stable prices. Further, 53 of 60 gas LDCs noted no change with respect to their regulator's receptivity to hedging, 1 reported increased receptivity, while 5 companies reported less receptivity to hedging. Of the 63 reporting companies, 17 noted that their regulator required a hedging plan to be filed for approval. Twenty companies indicated that state regulators placed restrictions on hedging parameters, such as choice of financial tools, date ranges and/or the quantities hedged; 3 companies noted their regulator requires a plan and places restrictions on hedging; and 29 companies noted that no plans or restrictions were required for their hedging programs.[11]

Q20. WHAT HAS THE RATIONALE BEEN FOR THE DISCONTINUANCE OF HEDGING PRACTICES AMONG THE CANADIAN LDCS?

A20. For those provinces that had previously engaged in hedging and have since discontinued the practice, the decision has been primarily the function of a cost benefit analysis, where it was determined that the benefits of hedging did not outweigh the costs. In addition, in both Ontario and British Columbia it was proposed that the risk management objectives may be achieved through less expensive alternatives. For example, if the risk management objective is to reduce rate volatility, in Ontario, the OEB found that a quarterly rate adjustment and equal billing plan sufficiently reduced volatility by providing rate smoothing effects. Similarly, in British Columbia, the BCUC concluded that hedging was not the way to deal with the potential for price increases and found that

[11] American Gas Association. *Energy Analysis: LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season* (July 31, 2012).

the benefits offered by other mechanisms (such as deferral accounts and PGA adjustments) could outweigh the benefits of hedging; and judging based on past hedging performance, the benefits in all likelihood would not justify the inherent costs. In addition, the panel of interveners appeared to be advocating for the offering of a hedged rate option to customers that would provide customers a choice for rate stability at an agreed upon price. This sort of tariff option is also employed in Manitoba, where the utility only engages in hedging to support its fixed rate programs, and has been ordered to cease any hedging associated with its variable rate offerings.

Q21. DO YOU AGREE THAT DEFERRAL ACCOUNTS AND PURCHASED GAS ADJUSTMENTS COULD REDUCE VOLATILITY SUCH THAT NO HEDGING WOULD BE REQUIRED?

A21. No. Though I agree that in periods of low volatility and declining prices this may be all that is required to minimize the effect of price increases, there is nothing to protect the customer from extreme and sustained price increases. The customer will eventually pay for the price increase. The deferral accounts or purchased gas adjustments largely create a cosmetic effect on prices by simply averaging the price spikes over a longer period of time. By the same virtue, the averaging of the spike also creates a form of stickiness in prices because the effect of the price spike tends to be longer-lived. Hedging strategies are more successful if they are structured to avoid the spikes instead of just smoothing the effect.

IV. CUSTOMER'S PREFERENCES

Q22. PLEASE DESCRIBE THE GAS SUPPLY ALTERNATIVES AVAILABLE TO GAZ MÉTRO'S CUSTOMERS.

A22. Gaz Métro's customers have access to three distinct gas services: i) direct purchase (about 3,000 customers) is available for all customers, but it is in effect only used by the largest customers, ii) fixed price service for customers with annual consumption between 7,500 m^3 and 1,168,000 m^3 (about 8,000 customers), and iii) system gas supply which consists of mainly commercial, small industrial and residential customers (about 178,000).

Fixed price gas supply service was introduced at the request of some customers who desired a fixed price for gas. Customers contracting for fixed price supply sign a contract with a third party marketer, while Gaz Métro retains the billing. Currently, this fixed price service is not available to residential and small commercial customers, unless they are part of a group of purchasers with combined annual consumption of 7,500 m^3 or more.

Q23. PLEASE DESCRIBE THE CUSTOMER COMPOSITION OF SYSTEM GAS SUPPLY.

A23. Gaz Métro's load is unusual, relative to other major gas utilities. There is relatively little residential load since most heating load is done with electricity in Quebec. The majority of Gaz Métro's load is with industrial customers (approximately 60%) while residential customers represent approximately 10% of the total load.

Q24. HAVE YOU INVESTIGATED HOW GAZ MÉTRO'S CUSTOMERS' NEEDS FOR VOLATILITY REDUCTION, PRICE STABILITY, AND PRICE PREDICTABILITY VARY AMONG CUSTOMER GROUPS; AND WHAT HAVE YOU LEARNED THROUGH THIS INVESTIGATION?

A24. Yes. Though none of the interveners interviewed[12] called for the termination of the Program, all indicated that the Program should be more cost effective. The consensus was the benefits of the Program should support its costs. It was generally agreed that some protection against price spikes should continue to be provided, but that it is important to understand the current volatility in the market, and the range of reasonable

[12] Concentric conducted four interviews with representatives of the following organizations: The Féderation canadienne de l'enterprise indépendante ("FCEI"), Option consommateurs ("OC"), Union des consommateurs ("UC"), and the Union des municipalités du Québec ("UMQ"). We also requested an interview with the Association des consommateurs industriels de gaz ("ACIG"), but the request was declined on the basis that virtually all industrial users purchase their commodity from third party marketers and have not been exposed to Gaz Métro's system gas supply costs.

expectations for price. Interveners expressed the view that if the range of expectations for price is not outside of tolerances, then hedging does not provide much benefit.

The Program parameters have been approved annually by the Régie based on requests filed by Gaz Métro. Gaz Métro has also filed detailed annual reports to the Régie on the structure and performance of the Program. However, the interveners would like to better understand the range of prices that customers are protected against and how Gaz Métro is conducting its hedging activities. All agreed that the currently-low natural gas price environment lessens the importance of hedging when compared to the past, especially since natural gas now enjoys a competitive price advantage over electric power in Quebec. What is important is that Gaz Métro has a program that is well managed and achieves the objectives that it seeks to achieve.

Q25. SHOULD THE CUSTOMERS' NEEDS, IN TERMS OF PROTECTION AGAINST VOLATILITY AND SHARP RISES IN PRICE, BE CONSIDERED IN MAKING AN ASSESSMENT OF WHETHER A HEDGING PROGRAM IS APPROPRIATE?

A25. Gaz Métro has a diverse customer base and the protection that is required varies among customer groups. Some of Gaz Métro's residential customers inhabit old inefficient gas-heated homes and are unable to change their consumption, but are extremely price sensitive. They do not have any options to manage their gas price volatility. They are captive customers in the truest sense and though they are the least able to bear the incremental costs of hedging, they are the most in need of price protection. Other customers such as municipal customers and small businesses place the emphasis on predictability. They would most like price certainty and prefer a multi-year, fixed-rate option.

A longer-term fixed-rate option could be attractive to many customers (i.e. landlords) subject to rent control, fixed income customers, small business. Still, other customers would prefer a range of options from minimal to no hedging, to more robust hedging, to a fully-hedged, fixed-price program. However, there was some concern over the customers' ability to make an informed decision. Since gas competes with electricity in

Quebec, it makes for a competitive issue for Gaz Métro, and increases the interest to protect the competitiveness of gas relative to electricity, but this is not a strong preference for Gaz Métro's customers.

Q26. PLEASE DESCRIBE RISK EXPOSURE OF CUSTOMER MIGRATION AND TO WHAT EXTENT HAS GAZ MÉTRO EXPERIENCED CUSTOMER MIGRATION IN THE PAST?

A26. The customers' ability to opportunistically switch from hedged system gas supply to a competitive supply service when prices are advantageous to do so, otherwise known as customer migration, may result in a material overhedged price exposure for a distribution utility. Customer migration creates price risk due to volumetric shifts in required load, almost always at times when system supply prices are disadvantageous relative to the market. That is to say that migration risk and price risk are highly correlated.

The customer migration rules are specified in the utility's tariff. Customer migration from system gas to a competitive supply service will generally not expose the utility to excess supply of natural gas at non-competitive prices, it simply increases the percentage hedged for the remaining customers. If the competitive suppliers' prices were consistently above those offered by the utility, Gaz Métro may experience an unplanned influx of customers migrating back to its system supply forcing the utility to purchase more gas and reducing the level of protection for the customers using system gas.

Q27. WHAT PRACTICES HAS GAZ MÉTRO ESTABLISHED TO MITIGATE THE PRICE RISK EXPOSURE AS IT RELATES TO CUSTOMER MIGRATION?

A27. After the occurrence of the severe weather events of 2005, whereby Gaz Métro experienced 20% customer migration due to direct purchase customers switching to system supply, Gaz Métro established rules restricting service migration. Those rules require that: i) A customer may leave system gas service only after a 6-month notice; and ii) a customer may enter the system gas service without payment after a 6-month notice. Otherwise, a payment of any positive value of the hedges will be charged on half the customer's projected annual load volumes. It should be noted as well that Gaz Métro builds an estimate of customer migration into its load forecast used for hedging (based on its historical experience).

Q28. HOW ARE THE RISKS ASSOCIATED WITH CUSTOMER MIGRATION TYPICALLY ADDRESSED BY REGULATED UTILITIES?

A28. Typically, customer migration is managed in one of two ways. First, like Gaz Métro, companies place restrictions on migration, i.e. restrictions on how often switching can occur and imposes specified waiting periods before switching may go into effect. For example, a number of programs prohibit a migrating customer from electing to return to utility service for a period of at least one year. Another approach is to establish "open seasons" during which customers can choose alternative suppliers. These practices will allow the utility sufficient time to manage its supply portfolio such that volume uncertainty is largely eliminated and the price exposure is mitigated. Oftentimes, if customers desire to switch on any other terms, they are required to pay a penalty that recovers the market differential between the tariff commodity price and the market price over some forward, pre-defined period in addition to any other ancillary costs.

Q29. IS THE FIXED RATE TARIFF OFTEN THE LOWEST COST TARIFF?

A29. No. One study aptly recognizes that though you can protect against volatility with long term contracting, it will ultimately raise the overall cost of the commodity. So, as it pertains to customer migration, offering a multi-year fixed price service may be a desirable option to secure a fixed commitment from customers, but it will likely not be a low cost option in terms of the commodity price. In reviewing how market volatility impacted capital investment in electricity markets, the Center for Study of Energy Markets observed that, "The risk of purchasing all of one's power at the marginal valuation is clearly high, but that does not change the fact that this volatility is reflecting the true facts of system operation. The efficient way to deal with this circumstance is to insure that most purchases are made under relatively stable, long-term commitments that reflect the averages of these volatile prices, but to still preserve the volatility that is truthfully reflecting the facts of the market. At its worst, the resource adequacy solution does not hedge against price volatility, but instead eliminates it by expanding resources to the point that prices are no longer volatile. This raises overall costs to pay for the capacity necessary to eliminate the volatility."[13]

Q30. DO YOU BELIEVE A FIXED PRICE TARIFF AND UN-HEDGED SYSTEM GAS SUPPLY WOULD SERVE THE NEEDS OF ALL CUSTOMERS?

A30. The input we received from interveners indicates a desire for equal billing and not just certainty in the price of the commodity that represents only a portion of the final bill. Though a multi-year, fixed-rate option may be a desirable alternative for many consumers who favor price predictability above all else, it may not be the desirable option for low-income consumers, whose primary interest is in least cost service. A fixed rate structure also creates the possibility of a rate shock when the fixed term expires; the new rate needs to reflect market conditions that may be significantly different from those during the time when the original rate was established. Alternatively, a fixed rate structure hassignificant downside risk exposure should prices during the fixed term settle below the fixed rate.

Q31. WHAT ARE YOUR RECOMMENDATIONS FOR ENHANCED PRICE RISK MITIGATION ASSOCIATED WITH CUSTOMER MIGRATION?

A31. Currently, Gaz Métro's practices outlined previously are very close to best practices in that Gaz Métro incorporates an estimate of customer migration in its load forecast, imposes restrictions on switching, i.e. 6-month waiting period and allows switching only once during each 12-month period, and employs a mechanism to recover any losses associated with switching if it occurs before the 6-month waiting period is up. This is a comprehensive solution that is well suited to Gaz Métro's overall service offerings. However, there may be a few enhancements Gaz Métro could consider.

[13] Center for Study of Energy Markets (CSEM), CSEM WP 146, *Electricity Resource Adequacy: Matching Policies and Goals James Bushnell* (August 2005) at 14.

Gaz Métro may consider adding a fully hedged multi-year fixed rate service offering if an equal-billing is requested. This would not eliminate the price risk associated with stranded hedges due to customer migration out of system gas supply, but would limit the number of customers that may migrate at any given time by requiring a long-term commitment for this option. Additionally, the waiting restrictions, switching restrictions and penalties would continue to apply. It is Concentric's observation that certain customers that desire a high degree of rate predictability would find this to be an attractive option, and correspondingly, would be the most likely to migrate from system gas supply. However, I do recommend the continuation of a market-responsive program for system gas supply.

V. COST AND BENEFITS

Q32. HOW HAS GAZ MÉTRO QUANTIFIED THE COSTS AND BENEFITS OF THE PROGRAM?

A32. Gaz Métro does not have a formal metric to quantify the cost or the benefit of the Program. Although not explicitly stated in its decision D-2012-158, the Régie implicitly identifies as "cost" of the Program the opportunity cost of hedging versus the alternative of not hedging. According to the Régie, the Program has added $1.39/GJ on the price for system gas customers over the past four years.

The losses incurred since November 2008 are solely the result of a decrease in market prices for natural gas. In other words, these losses are directly associated with the difference between the hedged price and the settlement price and are not associated with the actual cost of the financial instruments because they do not require an upfront payment (in the case of fixed-price instruments) or offsetting premiums as is the case with the costless collars. None of the costs identified by the Régie are associated with the cost of the derivatives.

The opportunity costs are a function of having placed hedges in a market environment that was higher than settlement prices. Figure 1 shows the yearly gains/(losses) of the

Program based on the hedging activity provided by Gaz Métro. The performance of the Program largely mirrors how the market prices have behaved since February 2009 when the prices have settled at the bottom of the trading range.

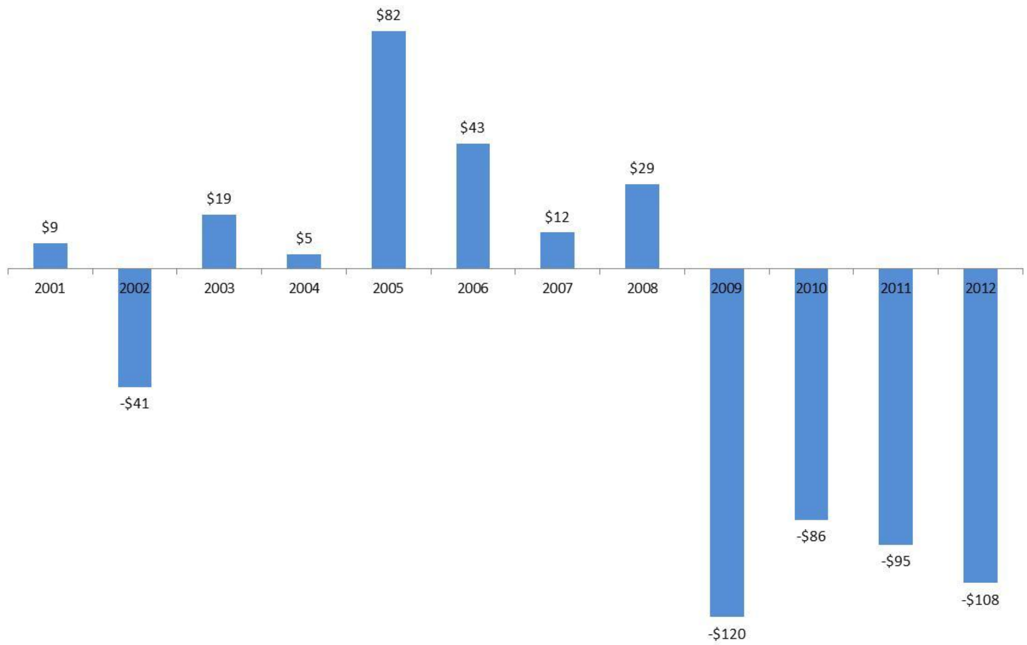

Figure 1: Hedging Gains/(Losses) in Millions of dollars
Source: Gaz Métro

To better understand how the performance of the Program fluctuates with the market we need to analyze the behavior of prices achieved by hedging and the price without hedging. Take for instance Figure 2 which summarizes historical forward prices for Alberta (AECO, NGX7A) and compares them against the prices that would have been achieved without hedging ("settle").

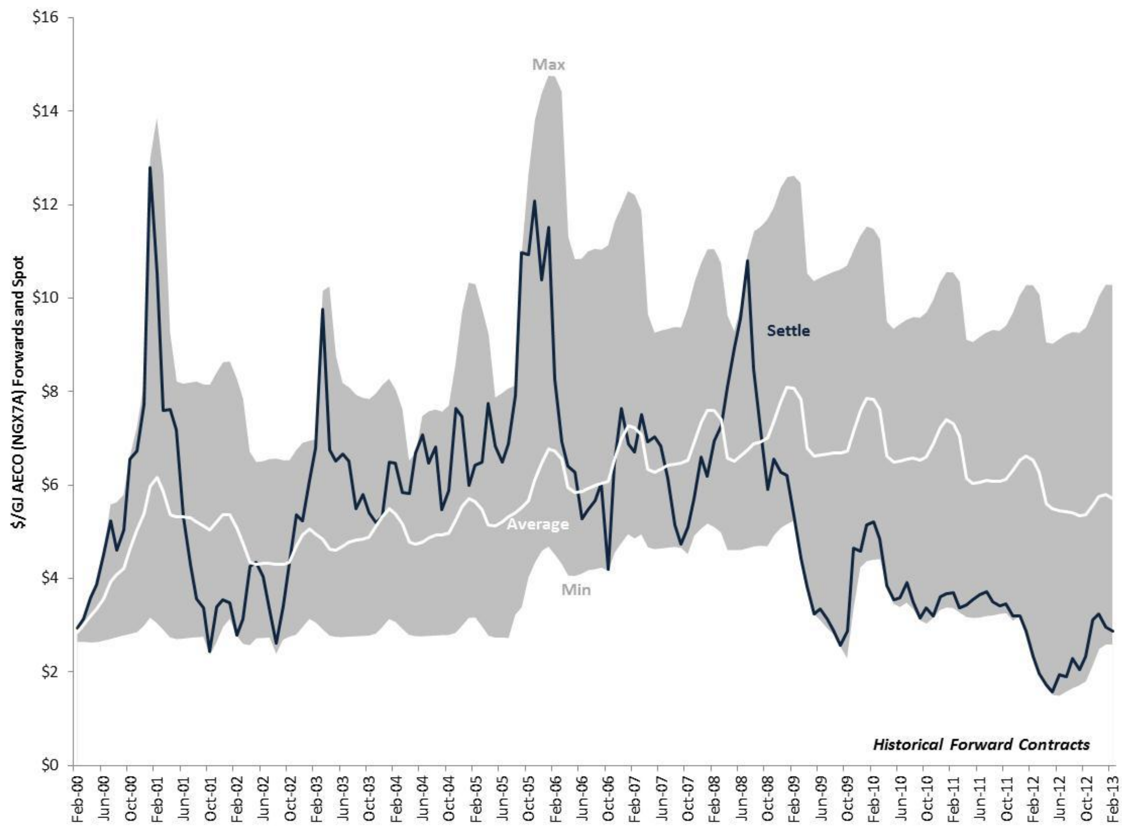

Figure 2: Historical Forward Prices for AECO (Range, Max, Min) and Expiration Price (Settle)

The price for AECO can be “fixed” (i.e. hedged) up to 60 months in advance with liquidity decreasing as a function of the term. The decision maker is therefore constantly having to choose between hedging a known price today, versus gauging the possibility that prices will be more favorable in the future or upon settlement. The price of the forward is known today; tomorrow’s forward prices or the ultimate settlement are unknown. The figure shows the range of prices for each contract during the 60 months of history (gray band), the average of this range (white line) and the last price of each contract settle (black line). The last price therefore represents the price paid if no hedging decision takes place, but it is unknown until the actual contract stops trading. A few highlights of the graph are as follows:

- The range of prices (gray band) is the historical range—or trading—for a particular forward contract and therefore represents the (cumulative) uncertainty of where the market believed the market might settle. Settle price is therefore unknown as the hedging activity takes place;

- Prior to February 2009, the settlement price followed an erratic movement around the range. Sometimes it settled at the maximum of prices, whereas sometimes it settled at the minimum of the range;
- Starting February 2009, the price has settled near the minimum price of the range;
- Progressively hedging through the life of the contract would have achieved a price near the average of the range (white line);
- Hedging from 2003 through the first half of 2006 compares very favorably to the option of not hedging. This is especially true in the aftermath of Hurricane Katrina (Fall 2005) when prices soared dramatically;
- Hedging from the second half of 2006 through the end of 2008 offered mixed results;
- Hedging after February 2009 compares unfavorably to not hedging because almost all prices before settlement were higher than settlement price; and
- Price levels starting February 2009 are in a similar range as prices seen at the start of 2000.

Q33. DO YOU THINK THIS QUANTIFICATION OF COSTS AND BENEFITS IS APPROPRIATE?

A33. It is a common measure of cost, but it is not an appropriate metric for managing the exposure. From the perspective of the implicit definition of "cost" as a synonym of opportunity cost, it is clear that the Program has represented a net cost of 13% since 2001, but in the last four years the cost has averaged 43% (Figure 4). While there is no evidence that Gaz Métro has had material deviations to the execution of the pre-approved strategy, the large opportunity cost is substantial and warrants changes to the current approach.

The opportunity cost, as defined above, is nevertheless a poor metric to guide the performance of the Program because the metric can only be measured once the specific forward month has expired. It is therefore not a metric that can be used as decisions are made well before the expiration of the contracts. The hedging program needs to be based on a metric that reflects the decision making as hedging activity is considered: hedge "now" or forego the opportunity of hedging. A more useful metric is a function of the ongoing comparison of a hedged price versus the current price (mark-to-market, or "MtM") or the risk of this MtM further deteriorating (Value at Risk, or "VaR").

Q34. HAVE YOU CONDUCTED AN INDEPENDENT ANALYSIS OF THE COSTS AND BENEFITS OF FINANCIAL DERIVATIVES PROGRAM USING GAZ MÉTRO'S QUANTIFICATION OF COSTS AND BENEFITS?

A34. Yes. I reviewed the hedges over the past ten years as provided by Gaz Métro and compared the prices hedged against the alternative strategy of "not hedging". I also calculated the volatility of prices achieved through the Program and the volatility of prices if no hedging activity had taken place.

Q35. HOW DO YOUR RESULTS COMPARE WITH THOSE OF GAZ MÉTRO'S?

A35. The results are consistent with those presented in Figure 4 and are also comparable with figures presented in the context of rate case filings and annual reports in prior years. The difference in our calculations and those by Gaz Métro is less than 5% and can be explained by small differences in prices as reported by several data suppliers. I consider this difference to be within a reasonable tolerance.

There are other alternative measures of "cost" and "benefit", but none of these alternative calculations produce different conclusions than the existing perspective where the cost is equivalent to the "opportunity cost" and the benefit is the reduction in volatility. Some of these alternative measures include the following:

a) Comparison of hedged price versus the price a year before - this comparison is useful to compare how the hedging activity compares against those prices that were relevant during the previous rate case;

b) Comparison to budget - this comparison is very typical (especially among industrials), but it is not feasible to implement because the Program is not referenced to a pre-defined budget; and

c) Targeted volatility - this comparison is useful to compare how the volatility of prices under the Program compared against a pre-defined tolerable level. This metric was not evaluated because there is no such parameter referenced in the Program.

Q36. IN YOUR VIEW, HOW IS THE FINANCIAL DERIVATIVES PROGRAM AFFECTING VOLATILITY MEASURES?

A36. Prices of the hedged portfolio have a lower volatility than the spot prices (23% versus 35%, Figure 3); this reduced volatility from the hedged price, but was achieved at the price of an increased opportunity cost (Figure 4).

Figure 3: Portfolio Hedge Price (Gold), Unhedged Price (Green) and Implicit Hedged Percentage (bars, right axis)

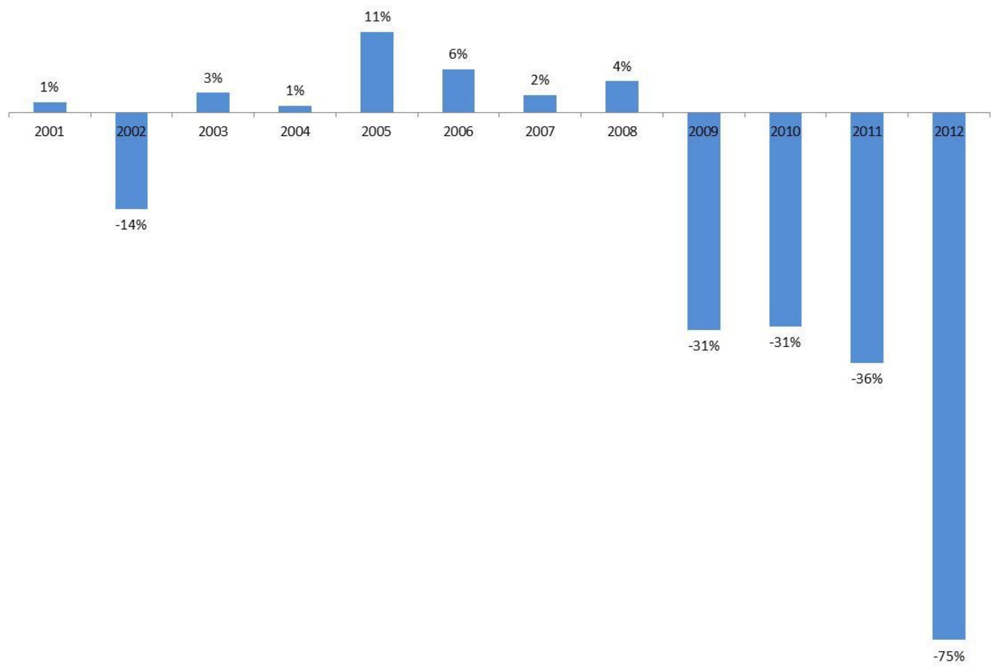

Figure 4: Hedging Gains/(Losses) as a Percentage of Cost without Hedging

Q37. IN YOUR OPINION, DO THE COSTS AND BENEFITS OF THE FINANCIAL DERIVATIVES PROGRAM REFLECT A CONSIDERATION OF MARKET CONDITIONS?

A37. No. The Program is centered on time-triggers and therefore does not adapt adequately to market conditions. According to the approved protocol, hedges are largely placed based on the number of months before expiration. In November 2011, Gaz Métro started using collars as a reflection of market conditions, but the downside-exposure risk of these collars was still significant.

Q38. WHAT DO YOU CONCLUDE FROM YOUR COST BENEFIT ANALYSIS?

A38. Gaz Métro has executed the hedging in accordance with the pre-approved strategy but the opportunity cost incurred in a low price and volatility environment, and the concerns expressed by both the Régie and the interveners, warrant changes to the current strategy.

VI. *BEST PRACTICES*

Q39. PLEASE DESCRIBE THE PREVALENCE OF UTILITY HEDGING PROGRAMS IN TODAY'S NATURAL GAS MARKET CONTEXT.

A39. According to an AGA study, most LDCs hedge a material portion of their supply needs, and there is a fair degree of uniformity in hedging strategies. A survey, conducted by the AGA, of 63 local gas utilities with service territories in 37 states, found that 81% of gas utilities used financial derivatives to hedge at least a portion of their supply. When asked how customers benefited from hedging, 41 of 51 companies noted reduced volatility, while 2 of 51 noted reduced gas costs as the main advantage, and 4 of 51 noted both. All companies that responded reported that regulators treated gains and losses equally.[14] Nearly all gas LDCs have regulatory cost recovery mechanisms for gas costs and the ability to pass on those costs to customers is dependent on those costs being determined as reasonable and prudent.

Q40. WHAT ARE THE PRIMARY COMPONENTS OF A BEST PRACTICES FINANCIAL DERIVATIVES PROGRAM?

A40. There is a great deal of literature dealing with utility hedging and best practices that can be summarized by the following primary elements of a functional hedging program:

1. Establish risk management oversight and governance;
2. Define hedging objectives and understand customer price-risk tolerances;
3. Develop a hedging strategy that includes when, how, and how much to hedge;
4. Identify performance metrics that can measure performance with respect to objectives and risk tolerance;

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[14] American Gas Association. *Energy Analysis: LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season* (July 31, 2012).

5. Evaluate, monitor and document costs and benefits of all potential hedging strategies, and document all hedging decisions, including decisions not to hedge; and

6. Report all hedging activities and costs in a timely fashion, including the periodic review of hedge plans with regulators, especially after a change in market conditions or in light of new information.

Q41. PLEASE DISCUSS THE IMPORTANCE OF ESTABLISHING HEDGING OBJECTIVES AND THE TRANSLATION OF OBJECTIVES INTO QUANTIFIABLE METRICS.

A41. The Program objectives and the quantification of those objectives into measureable tolerances and risk metrics that ultimately drive the Program should be at the core of the Program. The level of price protection should reflect the risk tolerance of customers. The utility and regulator should have an informed view of customer risk tolerance levels (both upside and downside risk) through surveys and educational workshops, but the workshop would not be a pre-condition to re-establishing the Program.

Q42. WHAT ARE THE COMMON MISSTEPS IN SETTING HEDGING OBJECTIVES? WHAT ARE COMMON MISCONCEPTIONS OF THE GOAL OF HEDGING?

A42. A common problem is a lack of specificity in the Program objectives. It is best to keep the focus on whether the Program continually adhered to its risk objectives, targets, limits, reporting and controls rather than on how attractive its results turned out to be relative to the spot market. The important question is not how much money was gained or lost by hedging, but rather whether the Program had the effect of keeping prices within pre-approved tolerances. Based on my experience with other companies, some common flaws can be summarized as follows. Please note that these alternative metrics are illustrative and are not recommended as specific enhancements to the Program:

a) "Beat the Market". Establishing the objective of beating the market is contradictory to hedging because hedging is executed to protect against an undesirable outcome and not to "make money". Hedging to beat the market is speculative because at the time hedging activity takes place (well in advance of expiration), the eventual spot price (i.e. the price that the futures will last trade at) is unknown. Hedging needs to reflect how the risk (as observed today) affects a risk tolerance (known today);

b) Save Money. Hedging with the objective of reducing costs cannot change expected costs, it can only protect against problems that arise at extremes, i.e. around the expected price. It is not reasonable to expect that hedging will lower costs over time, but instead, hedging will trim the extremes of potential outcomes without shifting the center;

c) Eliminate Risk. Hedging cannot remove all risks. In fact, it often creates new risks, such as liquidity risk, downside risk (opportunity cost) and counterparty exposure. Hedging is a choice of balancing the risk, not of avoidance;

d) Pay Less than Last Year. Hedging with the objective of paying less than last year (or some static historical benchmark) is not realistic because of the high degree of volatility and the fact that the average" price of natural gas is not static (i.e. the average price is changing over time and not converging to a value). Hedging based on a historical benchmark tends to produce underhedged position in a rising market and over-hedged positions in falling markets;

e) Hedge Only if Prices are Less than the Forecast. Hedging based on a perspective of what prices may ultimately end-up being is speculative because the perspective (if different from current market) cannot be hedged. For example, if a utility establishes its hedging strategy around a consultant gas price forecast for 2015 of $2.90/MMBtu[15], it will remain unhedged if prices are higher than the referenced price, or over-hedged if it is below it; and

[15] MMBtu = 1.055056 GJ

f) Hedge Because it is Time to Hedge. Hedging primarily based on a calendar trigger (e.g. hedge 50 percent 12 months in advance) overlooks the essential purpose of hedging: hedge to avoid a risk that is not tolerable. It is true that hedging well in advance (typically at least 2 years) has historically yielded good results, but the total percentage to hedge under this logic should be limited.

Q43. WHAT IS YOUR OPINION OF THE GAZ MÉTRO'S PROGRAM OBJECTIVES?

A43. The objectives lack the specificity to meaningfully evaluate performance and this makes it difficult to substantiate the benefits or costs of the Program. More specifically,

- The objective to stabilize the cost of natural gas by reducing portfolio volatility is a legitimate objective, but the activities to support such a Program are not clearly supporting its fulfillment. The Program is dominated by a time component but there is no systematic evidence that volatility is quantified or decisions are made to explicitly reduce the volatility;
- The objective to limit the impact of price increases also lacks specificity because it doesn't adequately define what a price increase is, nor does it define the way that the Program will become aware of how to measure price increases and the decisions that will be made to limit the impact of price increases. One might even argue that a more careful drafting of the first objective (stabilize cost by reducing volatility) will make the second objective (as currently worded) irrelevant;
- Preserving the competitive position of natural gas to electricity fails to adequately define the range or competitiveness. Preserving competitiveness between electricity (regulated and fixed) and natural gas (unregulated and volatile) is flawed because it is comparing a commodity that has a heavy component of certainty (electricity) versus a commodity that doesn't (natural gas); and
- Based on conversations with interveners, comparative competitiveness to electricity doesn't seem to be a meaningful objective to consumers because fuel switching on a discretionary basis (i.e. short-term) is limited and more structural

fuel switching requires significant capital decisions. There may be some fuel switching incentive, but the preponderance is not clear.

Q44. IN PRACTICE, HOW DOES A UTILITY ESTABLISH THE RISK TOLERANCES?

A44. Risk tolerances are a direct translation of how prices of natural gas will impact customers, or change their consumption in an unintended way. It is directly linked to specific performance objectives and should be quantified such that the performance against the objective is measureable, e.g. protecting against an increase to $8.00/MMBtu, a level that customers would have indicated as intolerable. Alternatively, managing the effect of gas price volatility such that the year-over-year increase in retail rates is less than 5%, at a specified level of confidence; or hedge to assure, within a specified confidence interval, that gas costs will not diverge unfavorably from market by more than 2%, etc.

Q45. WHAT ARE THE VARIOUS TYPES OF HEDGING PROTOCOLS AND HOW ARE THEY COMBINED IN A 'BEST PRACTICES' FINANCIAL DERIVATIVES HEDGING PROGRAM TO ACHIEVE THE APPROPRIATE AMOUNT OF RISK MITIGATION GIVEN THE MARKET CONTEXT?

A45. When applied to energy hedging, a protocol is a method that defines how a utility will achieve price stability and guard against price spikes. A protocol differs from a strategy in that it does not provide the specific details of how the goals will be achieved. It also differs from a policy in that a policy establishes a mandate. Hierarchically, a policy provides a mandate that is detailed in a procedure. The procedure will contain a series of protocols (examples below), a strategy and tactics to achieve those goals.

The two most common protocols are as follows. They may differ in name, but the functional purpose of each seems to be consistent across different programs:

a) Defensive. This is a protocol that mandates hedges based on a specific risk exposure as further described below; and

b) Programmatic. This protocol is very similar to what Gaz Métro has executed in the current Program and mandates placement of hedges well in advance to avoid hedging in periods where volatility is greatest. This protocol however is typically limited to no more than 25% because of the potential consequences of hedging a poor price. Variations of this protocol includes procurement practices such as dollar-cost-averaging.

Q46. PLEASE DEFINE PROGRAMMATIC HEDGING AND WHAT PART IT SHOULD PLAY IN AN OVERALL HEDGING PROGRAM.

A46. Most hedging programs include a programmatic protocol where hedges are executed uniformly over time in accordance with a set schedule. The primary basis for programmatic hedging is the reduction of price volatility in the hedged portfolio by hedging further out into the hedge horizon, since volatility is more acute in the near months and diminishes as you move further out in time. Additionally, since price volatility tends to be more extreme in upward price movements than downward, programmatic hedging tends to remove more negative price activity than positive. Generally, a schedule is set to hedge a specific percentage of the portfolio over a given time period. This means that a limited portion of the portfolio can be associated with a time-trigger, but this should be complemented by a protocol that takes into account current market conditions (i.e. the Defensive Protocol);

Generically speaking, programmatic hedges may be defined by a desired hedge requirement; let's say 25% of hedged portfolio, by the hedge horizon for the programmatic hedging, i.e. 3 years or 36 months. In this case, each month, the utility would hedge 0.69% of its forecast load (25%/36 mos.), such that after 36 months, the near month is exactly 25% hedged.

Programmatic hedging provides for the smoothing of market movements by diversifying hedge activity over time and capitalizes on the low volatility and price stability of the outer months, but inevitably creates downside exposure that needs to be measured and managed. It removes the incentive to attempt to 'time the market' or engage in speculation; and avoids circumstances that could lead to "hedger's regret" by not committing the utility to a single hedged price that turns out to be unattractive relative to the market.

Q47. HOW SHOULD THE PROGRAMMATIC HEDGE PROTOCOL RESPOND TO THE MARKET ENVIRONMENT?

A47. The programmatic hedge protocol responds to the market environment by limiting the targeted hedge amount and the hedge horizon. Overall, the goal of programmatic hedging is to provide some minimum level of hedging prior to the onset of acute volatility in the near months. We find that best practices" incorporates a programmatic hedging element but to a limited extent so as not to create excessive downside risk exposure. It is tempting to tinker with the programmatic hedges as a function of the market, but it is best to limit the size to a manageable level given the cyclical nature of the market.

Q48. WHAT FACTORS SHOULD BE CONSIDERED TO MAKE A DETERMINATION OF HOW MUCH PROGRAMMATIC HEDGING SHOULD BE PERFORMED AND OVER WHICH HORIZON?

A48. The cyclical nature of prices should be analyzed. The critical element that distinguishes programmatic hedges from defensive hedges is that the latter is governed by a balance of upside and downside risk exposure, whereas the former is only limited by a targeted amount. Historically, hedging in advance takes advantage of prices that reflect supply and demand forces whereas short-term markets tend to also include influences from financially-oriented trading activities. In principle, the hedge horizon should therefore be long enough to avoid the consequence of high volatility, but short enough to avoid paying a premium for the lack of liquidity.

Q49. WHAT DO YOU MEAN BY DEFENSIVE HEDGING?

A49. Defnsive hedging is hedging to protect against undesirable volatility. Defensive hedging is a protocol that associates hedging activity as a balance between the upside and downside risk tolerance and is typically defined for a hedge horizon of between 12 and 18 months in advance. In simple terms, under a Defensive Protocol risk is measured and hedging takes place if the upside risk exposure is intolerable, but only if the downside risk it creates is tolerable. It therefore hedges enough to keep a balanced risk exposure.

Defensive hedges are an important risk protection to ensure that gas costs remain within tolerances for the hedge period. Since risk is measured on a continuous basis, it reflects the changing market conditions as the prices evolve, and volatility either increases or decreases.

A defensive protocol is structured with the customer in mind. Risk tolerances are quantified and established as guideposts to ensure the ratepayer is protected from gas costs that exceed the extremes or that the competitive position is retained. Technically, defensive hedging is based on a distribution of outcomes, and when an undesired outcome falls outside the pre-established statistical confidence level[16], a hedge action is triggered to mitigate the risk of the undesirable outcome such that it continues to fall within the selected confidence level. Hedging actions are triggered by changes in market volatility and, as such, are particularly useful in addressing near term risk exposure since volatility increases as we approach the Prompt month. Typically, the most extreme price spikes occur within one year of contract settlement, so defensive hedging protocols are most effective when focused on the next year or two, leaving the following years for programmatic hedging.

Defensive hedges will therefore lead to a hedge profile that is more accommodating to market exposure. If the downside risk exposure dominates upside risk, then the resulting

[16] The confidence level typically is 95%, 97.5% or 99%.

hedged position will be small. Conversely, if the upside risk exposure is higher than the downside risk, hedged positions will tend to increase.

Q50. WHAT DO YOU MEAN BY UPSIDE AND DOWNSIDE RISK EXPOSURE?

A50. That risk for an end-user is two-fold. Energy prices are amongst the most volatile for commodities, which means that the future spot price of a commodity is unknown. For instance, price for natural gas at the beginning of 2008 averaged $6.50/MMBtu, but there was great uncertainty whether prices were going to increase or decrease from that point forward. Looking at the May 2012 Futures contract on CME[17] we see that prices eventually rose from $6.25 to $10/MMBtu by May 2008, but then dropped progressively to a settlement near $2.00/MMBtu. A hedging program therefore needs to be aware of the existence of upside risk (from $6.25 to $10/MMBtu), but also of the risk of prices decreasing significantly (from $10 to $2/MMBtu).

Upside risk exposure is therefore the risk that prices will increase and you will pay more tomorrow than what you would have paid if you had hedged today; and downside risk exposure is the risk that the price you have locked in through hedging will ultimately be higher than the market settlement price (prudence risk or opportunity loss). In today's market context, I find that most hedging programs are designed to address upside risk exposure based on a concern that natural gas prices will increase.

Best practices with respect to defensive hedging incorporates not only the tolerances associated with upside risk exposure, but also that of downside risk exposure, such that hedging decisions are moderated to accommodate both exposures. Also, the market context should inform the weight that is placed on either upside or downside risk, i.e. in a low-volatility, declining market, downside risk becomes more important and in a rising market, upside risk becomes more important. For example, if your upside risk exposure is telling you to hedge 30 contracts, but your downside risk exposure is showing that by

[17] CME Group is the largest future exchange company.

hedging any more than 10 contracts, you will have exceeded your downside risk exposure tolerance, if both exposures are considered equally important, you would hedge 20 contracts. If you are not concerned at all with upside risk exposure, you would only hedge 10 contracts, and correspondingly, if you have no concern for downside risk exposure you would hedge all 30 contracts.

*Number of Contracts to Hedge = (Contracts to Protect Upside Exposure * Balancing Factor) + (Contracts to Avoid Untolerable Downside Exposure* (1-Balancing Factor))*

Q51. PLEASE DISCUSS THE PREVALENT HEDGING INSTRUMENTS USED BY GAS LDCS TO MANAGE COMMODITY PRICE RISK.

A51. Financial tools for managing gas price volatility include futures and swaps, options and collars, basis swaps and weather derivatives. Fixed-price instruments (e.g. futures, forwards and swaps) provide price certainty to buyers and sellers and are generally used by gas utilities to protect the upside price risk. However, they do create downside risk exposure in that the locked in price may exceed prevailing spot market prices for the contract month. Basis swaps are used to lock in fixed transportation differentials between pricing points and delivery points and also create downside risk exposure to the extent that the locked in differentials may exceed the actual basis at settlement.

Options and collars provide price protection, providing the option but not the requirement to purchase (or sell) at the strike price. Options may be purchased for a premium, which factors in the volatility of the contract and the strike price relative to where the contract is trading at the time of purchase. In practice, options are often purchased as part of a collar strategy, often costless, where the buyer of the call option also sells a put option and uses the premium of the put option to offset the premium paid on the call option. The strike price of the put option is set based on the strike price that would make the collar costless, given the strike price on the call premium. These instruments are used to purchase protection against price spikes, but allow some participation in downward price movements. Sometimes a second put option is purchased at a strike price immediately below that of the put that is sold, thereby limiting the downside risk.

According to an AGA survey that reviewed supply portfolio management among 63 gas LDCs during the 2011-2012 winter heating season, fixed price contracts and options were most often cited (by 26 companies) as the preferred instrument most often used to hedge a portion of gas volumes delivered on peak day. Other regularly used financial tools included swaps (22 companies) and futures (14 companies). Additionally, 61 of 63 LDCs reported using natural gas storage as a hedging tool, of those, 33 LDCs hedged between 25 and 51% of winter heating season supplies using underground storage; and another 20 LDCs employed this physical hedge for 1 to 25% of their supply portfolio. Finally, only 4 of 63 companies used weather derivatives.[18]

Q52. DOES THE HEDGING INSTRUMENT SELECTED DEPEND ON THE HEDGING PROTOCOL UTILIZED?

A52. No. In general, the selection of the instrument depends on how the particular instrument addresses the risk exposure that we are looking to mitigate. As outlined before, a fixed price position provides absolute upside risk protection for the amount that is hedged, but creates a downside risk exposure.

The appropriateness of the instrument is a direct consequence of the risk exposure being managed, and not a function of the protocol being implemented.

Q53. WHAT PART DOES NATURAL GAS STORAGE TYPICALLY PLAY IN AN OVERALL HEDGING STRATEGY?

A53. Hedging instruments for managing natural gas price volatility can be divided into three different categories: physical tools, financial tools, and structured, non-standard agreements. The first and most important physical tool that most natural gas utilities use

[18] American Gas Association. *Energy Analysis: LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season* (July 31, 2012).

to manage gas price volatility is physical natural gas storage. Storage is a short term (typically less than 1 year) hedging strategy, characterized by summer injections for winter peak load. For utilities that do not have storage in their market area, they may contract or invest in LNG peak shaving or swing storage (park and loan). Storage helps utilities avoid expensive firm capacity to transport gas from the producing region by having storage in the market area, also enhancing winter deliverability. In an AGA survey of 63 gas utility companies, the tool most used to manage price and physical supply risk was "storage."[19]

Q54. WHAT PART DO LONG TERM CONTRACTS TYPICALLY PLAY IN AN OVERALL HEDGING STRATEGY?

A54. Fixed price physical delivery contracts are also used as a hedging tool against price increases, and can be contracted for durations ranging from short term to long-term, however, fixed priced contracting for long durations is not often used by utilities given concerns of regulatory prudence disallowances. Some utilities may be able to alter operations, such that some volumetric risk is mitigated. An example of this is curtailing interruptible customers or instituting an operational flow order curtailing delivery of natural gas. These measures are also powerful physical tools to hedge price risk or volume risk. Lastly, some utilities have made the long term commitment of purchasing production area reserves, locking in fixed gas costs for the very long term.

Q55. HOW FAR OUT INTO THE FUTURE IS HEDGING ADVISABLE?

A55. No more than 24 months in advance for Defensive hedges and no more than 48 months before expiration for Programmatic hedges. Utilities tend to have a hedge horizon that is not longer than four years into the future. Natural gas futures markets trade ten years into the future (at most); only the first three to four years of futures have a high degree of liquidity. According to the AGA survey referenced above, 43 of 51 LDCs responded that

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[19] American Gas Association. *Energy Analysis: LDC Supply Portfolio Management During the 2011-2012 Winter Heating Season* (July 31, 2012).

they hedge the 7 to 12 forward months for a portion of their supplies, while 42 of 51 LDCs employ a 6-month or less time frame, 27 use a 12 month or greater approach to hedging; and of these, 23 LDCs employ all of the above.[20]

As one goes further out, bid-ask spreads widen and the carry (time value of money) implicit in future prices may make outer-year contracts unattractive. Further, long-term hedges (exceeding 3 or 4 years) may be viewed by regulators as a gamble, who may not be sympathetic if the market turns against the utility and the utility is left paying out–of-market prices.

A hedge horizon of no more than two years doesn't necessarily imply that the utility will be obligated to hedge starting two years into the future. The actual amount of hedging and the timing of hedges will be dictated by the specifics established in the protocols. For instance, let's assume that the hedge horizon is two years, and that the defensive hedges will take place one year in the future, programmatic hedges will be implemented between one and two years into the future.

A hedge horizon of no more than 24 months is statistically confirmed by looking at how volatility evolves as time to expiration decreases. Figure 5 below summarizes ten years of daily observations that measures volatility on a daily basis and clearly shows that volatility for terms greater than 24 months is (on average) stable.

[20] Ibid.

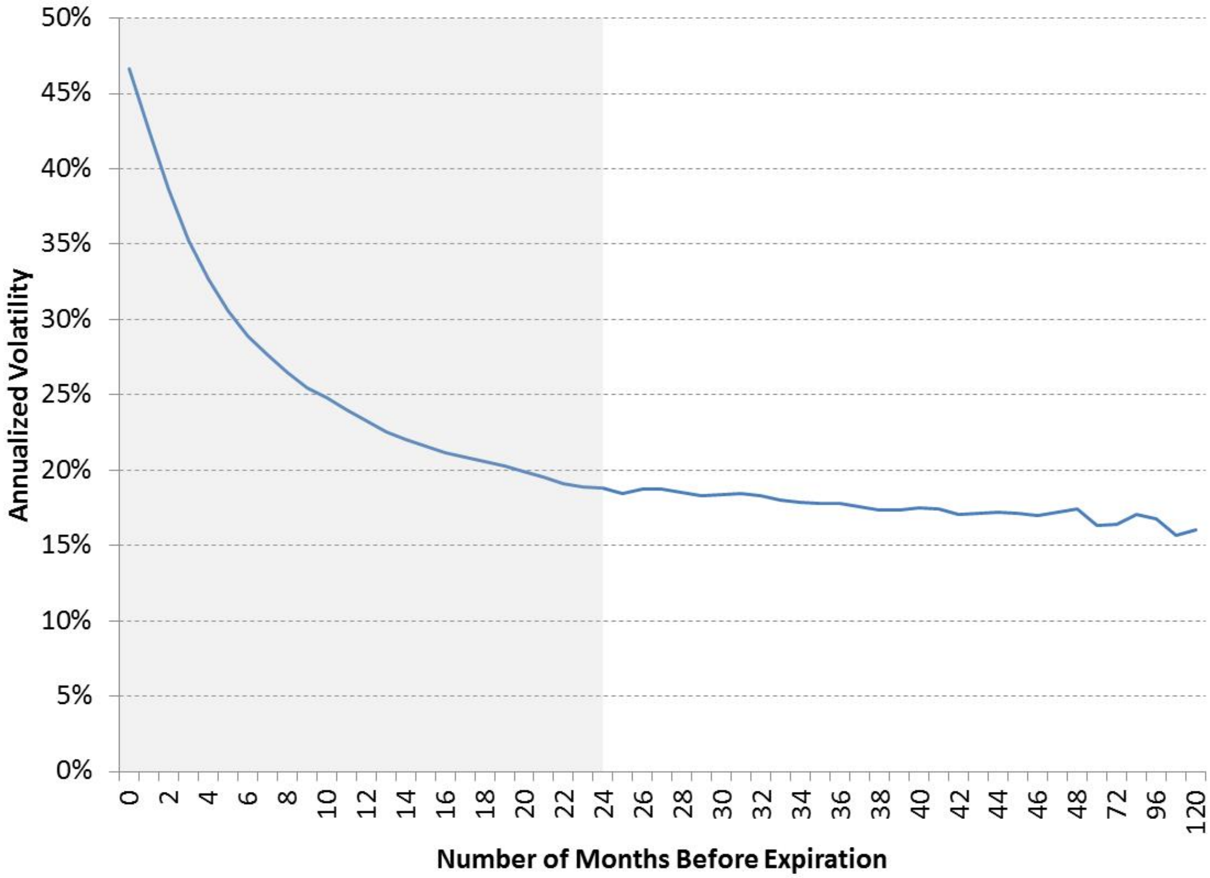

Figure 5: Evolution of Volatility to Expiration for Henry Hub using daily observations from 2003-2013

Figure 5 therefore shows that hedging more than 24 months in advance may not likely protect against price movement because prices do not tend to change significantly for terms greater than 24 months.

VII. PROGRAM ENHANCEMENTS

Q56. PLEASE DISCUSS THE ADVANTAGES AND DISADVANTAGES OF THE CURRENT PROGRAM AND DISCUSS HOW IT MAY DIFFER FROM THE IDEAL.

A56. More than a risk management practice, the Program reflects a procurement practice. Philosophically, a program should be based on the three core elements: awareness of risk, measurement of risk and a decision making process to avoid undesirable risk exposures. The current Program does not show evidence of being centered on awareness and measurement of risk, and the decisions to hedge (quantity, instruments or timing) are not based on avoidance of undesirable risk exposures. The Program is largely hedging because it is time to hedge, and it is hedging to a targeted quantity. A risk-based program will hedge based on the monitoring of risk exposure, and will hedge to a quantity sufficient to avoid undesirable risk exposure.

It is not uncommon for regulated utilities to have a program that is dominated by a time component because they were structured in an era of a general rise in prices where hedging early paid off. More recently, there is clear evidence to suggest that this practice is being challenged as the performance of these programs has deteriorated in the presence of a downward trend in prices. These programs were crafted in an era where the risk of upside exposure was dominant, whereas the last four years have highlighted the risk of downside exposure.

The current evaluation of this Program is happening in the context of historical changes in market expectations. Deciding not to hedge based on a balanced approach between an avoidance of upside and downside risk exposure is not the same as eliminating the Program as a reaction to poor historical results or a perspective on the market. A market perspective is not a hedge, and making an informed decision not to hedge is not the same as making no decision at all.

Our conversations with the interveners lead us to conclude that there is a general misunderstanding of what the Program is, what it is it trying to do, how it is trying to achieve its objectives and how to measure performance.

- Conversations with the interveners indicate a limited understanding of the Program. The losses over the past four years have been the result of having hedged at a high price and the market settling at lower prices than those hedged. When the hedges were made the settlement price was an unknown and the opportunity cost could not have been measured in advance of settlement.;

- The opportunity cost is not a cost that is known upfront, it is only known at expiration of the contract;
- The guidelines of the Program do not sufficiently describe the process and instruments that are being used to execute the Program;
- The conversations implicit in the historical rate cases I reviewed seem to reflect that there is a gap in the understanding of hedging instruments and the risk exposures that they create or address. A fixed price position does curtail upside risk exposure, but it creates full downside risk exposure given the possibility that the price that was hedged may turn-out to be more expensive than the eventual settlement. The same is true for the costless collars that have been recently implemented, while it is true that the collar offers downside participation (for price movements within the collar), the reality is that the market settlements have been much lower than the price triggers of the collars resulting in significant downside exposure (the same criticism of a fixed-price position but to a lesser extent);
- There is no evidence to suggest a set of metrics to measure performance or to gauge how the Program has been a net benefit or cost. There is no explicit definition of what "cost" or "benefit" is but there is an implicit association that cost is the same as "opportunity cost" and benefit is "stability of prices".
- Measuring the performance of the Program based on the alternative of not hedging is a common and inevitable comparison, but it is not a useful metric to guide the Program because the opportunity cost will only be known once the particular contract has settled and no more decisions can be made. There is no evidence to suggest that the potential" opportunity cost is being monitored in advance of settlement when an actual decision can be made. Measuring the performance of the Program solely on the opportunity cost sends the wrong incentive to the performance of the Program because it typically leads to a perspective to "beat the market" and this is speculative; and
- There is no evidence to evaluate how the hedging horizon was chosen, or how the hedge horizon will be adjusted based on the risks in the marketplace. The current

hedge horizon is 48 months with the intent of capturing prices with lower volatility, but this term is also introducing the possibility that far-dated prices that are currently higher than spot market may progressively soften as their respective expiration approaches (just as has occurred over the past 4 years where prices have settled at the low of the range of trading).

Q57. DO YOU BELIEVE THAT THE CURRENT CONTEXT FOR HEDGING HAS CHANGED SINCE GAZ MÉTRO'S PROGRAM WAS DEVELOPED?

A57. It is evident that hedging programs designed for highly volatile, rising-price environments may not be well-suited for the current low-volatility, low-price scenario. It is also not surprising to see Regulators or Boards suggest a review or suspension of the programs in light of high opportunity costs over the past four years, or the "common knowledge" that the natural gas industry has changed dramatically with the advent of non-conventional sources (i.e. shale gas), prices have been trading in the $2-$4/Gj range and volatility has diminished from a traditional 40% to approximately 30% per annum.

This change in the market can be observed in Figure 6 by summarizing prices of natural gas at Henry Hub by month and year for the last ten years and then coloring the observations according to where they stand in terms of a percentile distribution. Cells colored in blue reflect low prices (i.e. in the lower percentiles of the distribution), red prices reflect high prices (i.e. in the higher percentiles of the distribution) and non-colored cells reflect normal (i.e. average) prices. Based on the coloring used, it is easy to see that natural gas prices suffered a structural change after 2008 and this clearly aligns with the discovery and explotation of non-conventional sources of natural gas. The impact of shale gas has been broadly discussed but Figure 6 clearly confirms this from a statistical perspective. For the purposes of enhancements to the hedging strategy we need to take into account that the relevant timeframe is after 2009.

Henry Hub Spot 2003 - 2013

Average Historical Price ($/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	All
2003	$ 5.43	$ 7.59	$ 6.12	$ 5.24	$ 5.77	$ 5.85	$ 5.07	$ 4.97	$ 4.63	$ 4.65	$ 4.43	$ 6.05	$ 5.48
2004	$ 6.10	$ 5.40	$ 5.38	$ 5.70	$ 6.30	$ 6.28	$ 5.93	$ 5.45	$ 5.09	$ 6.31	$ 6.16	$ 6.62	$ 5.89
2005	$ 6.14	$ 6.12	$ 6.92	$ 7.21	$ 6.49	$ 7.15	$ 7.58	$ 9.37	$ 12.32	$13.58	$10.33	$ 13.14	$ 8.88
2006	$ 8.72	$ 7.63	$ 6.87	$ 7.19	$ 6.27	$ 6.21	$ 6.06	$ 7.23	$ 5.03	$ 5.70	$ 7.34	$ 6.83	$ 6.75
2007	$ 6.43	$ 8.05	$ 7.10	$ 7.59	$ 7.63	$ 7.42	$ 6.22	$ 6.27	$ 6.04	$ 6.69	$ 7.10	$ 7.11	$ 6.96
2008	$ 7.91	$ 8.50	$ 9.38	$ 10.13	$ 11.24	$12.60	$11.26	$ 8.31	$ 7.72	$ 6.78	$ 6.68	$ 5.87	$ 8.87
2009	$ 5.27	$ 4.55	$ 3.98	$ 3.51	$ 3.80	$ 3.81	$ 3.40	$ 3.18	$ 2.94	$ 3.97	$ 3.66	$ 5.28	$ 3.94
2010	$ 5.85	$ 5.35	$ 4.33	$ 4.03	$ 4.12	$ 4.79	$ 4.62	$ 4.36	$ 3.89	$ 3.46	$ 3.68	$ 4.24	$ 4.38
2011	$ 4.48	$ 4.11	$ 3.96	$ 4.23	$ 4.31	$ 4.55	$ 4.42	$ 4.07	$ 3.91	$ 3.56	$ 3.25	$ 3.19	$ 4.00
2012	$ 2.70	$ 2.52	$ 2.19	$ 1.95	$ 2.42	$ 2.44	$ 2.93	$ 2.86	$ 2.84	$ 3.30	$ 3.55	$ 3.34	$ 2.75
2013	$ 3.33	$ 3.32	$ 3.78	$ 4.16	$ 4.05	$ 3.85	$ 3.56						$ 3.76
All	$ 5.70	$ 5.72	$ 5.42	$ 5.54	$ 5.68	$ 5.90	$ 5.75	$ 5.62	$ 5.47	$ 5.78	$ 5.61	$ 6.15	$ 5.69

Source: CEA using data from SNL

Percentile Coloring

1%	5%	10%	15%	20%	30%	40%	50%	60%	70%	80%	90%	95%	99%

Figure 6: Historical Perspective of Natural Gas Prices

Q58. PLEASE DESCRIBE THE IMPLICATIONS OF SHIFTING GAZ MÉTRO'S SYSTEM GAS SUPPLY TO DAWN.

A58. The Dawn Hub is one of the most liquid, transparent natural gas trading centers in Canada, with over 9.3 Bcf/d of near-term (e.g. spot) trading activity and day ahead trading volumes of 0.75 Bcf/d but of limited financial liquidity for forward transactions.[21] A significant volume of spot transactions take place between LDCs, marketers and natural gas-fired power generators, who also hold storage at the Dawn hub.

The Hub's strategic location in Dawn, Ontario, 22 miles southeast of Sarnia, provides access to most major supply regions in North America, but it has never been a significant trading point for financial forwards (when compared to AECO or Henry Hub). Shippers can receive incoming natural gas from multiple routes in Western Canada, the Rockies, Mid-continent, and the Gulf of Mexico, and transport it either downstream to Eastern Canada and the Northeastern United States, or upstream to markets in the mid-western

[21] The Chicago Mercantile Exchange offers (i.e. clears) an over-the-counter "Dawn Natural Gas (Platts IFERC) Basis Futures" 36 consecutive months out, but trading is limited. The product symbol under CME Globex is "ADW" and "DW for CME Clearport.

United States. The Dawn storage complex, which is owned by Union Gas Ltd., is the largest concentration of underground storage in Canada, with over 155 Bcf of high deliverability storage in 23 depleted reservoirs. When operating at peak capacity, the Dawn facility can inject or withdraw just under 2.8 Bcf/d. In addition to the storage owned by Union, Enbridge Gas Distribution also owns approximately 100 Bcf/d of storage in the Tecumseh storage facility located near the Dawn Hub.

Similar to the broader North American pricing trends, the Dawn Hub has also experienced the similar decline in overall spot prices and a decrease in volatility in the past few years. As shown in Figure 7, actual spot prices at Dawn experienced a steady downward trend between 2005 and 2012. Existing spot prices at Dawn are in the US$3.75/MMBtu to US$4.00/MMBtu range. This decline can be explained by the need of pricing natural gas from Western Canada at a competitive price to natural gas from the Shale producing areas (such as Pennsylvania).

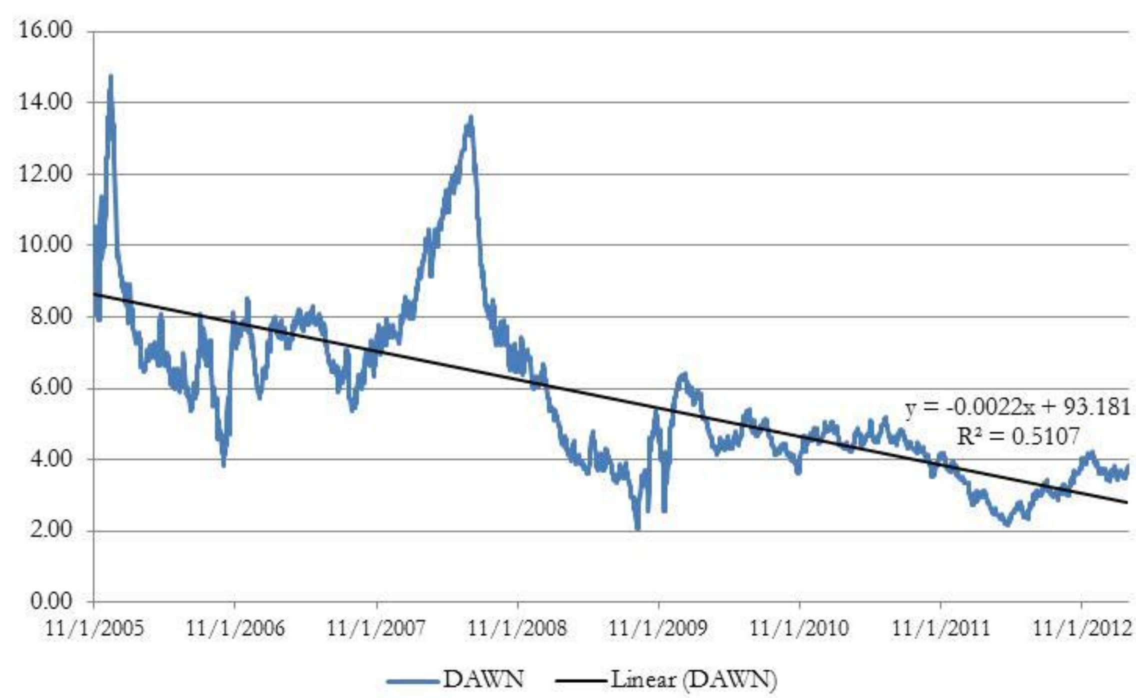

Figure 7: Dawn Spot Price Trend (in US$/MMbtu)

According to an October 2012 Ontario Energy Board market price forecast for the Ontario wholesale electricity market, the forecast average Dawn natural gas price for the twelve months commencing November 2012 was C$3.62/MMBtu[22]. The forecast average price over the entire 18-month period was C$3.76/MMBtu.

In addition to the new pipeline infrastructure and expansion projects discussed in detail below, several existing pipelines recently began increasing exports from the United States into Eastern Canada and these flows are expected to continue. These include National Fuel Gas' interconnection with Tennessee Gas Pipeline at Ellisburg, Pennsylvania, to the TransCanada Pipeline at Niagara near Niagara Falls; Iroquois Gas' connection from Waddington, New York, to Ontario; and National Fuel Gas' Empire Pipeline from Corning, New York, to Ontario.

While natural gas prices at Dawn have reflected a declining trend over the past few years, the volatility has declined in the past few years as well. Because prices are lower, the absolute level of volatility has declined even more than the relative level (in relation to the mean.) The chart below shows annual price volatility at the Dawn Hub between 2005 and 2013.

[22] Navigant Consulting Ltd., *Ontario Wholesale Electricity Market Price Forecast*, Ontario Energy Board, (October 12, 2012)

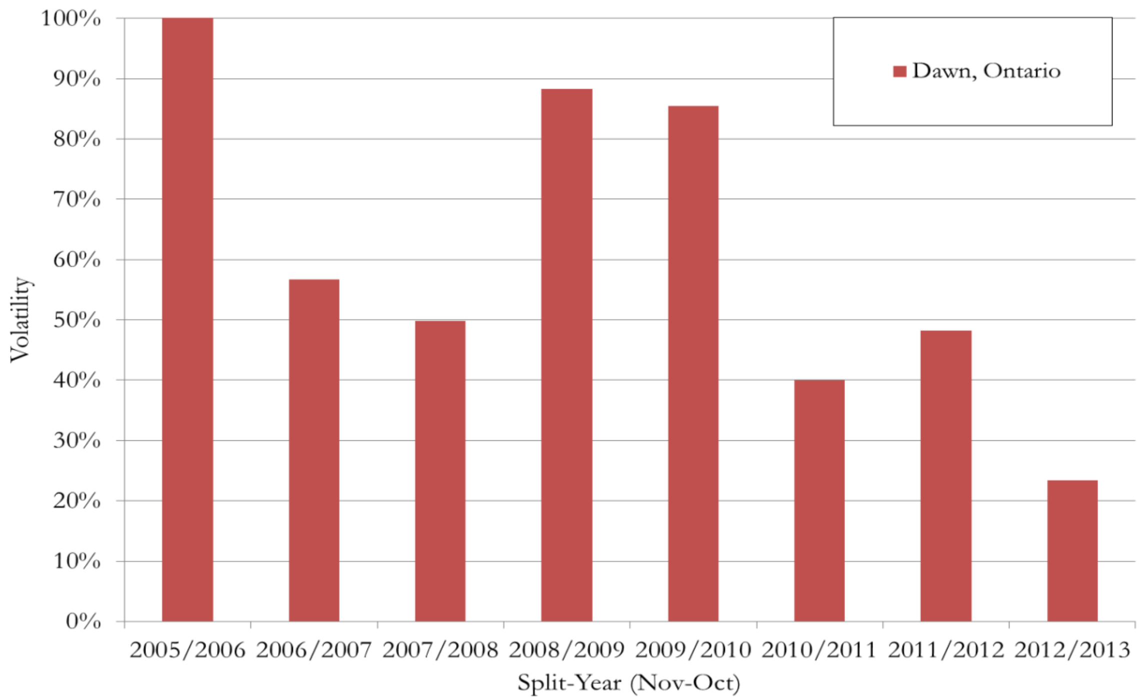

Figure 8: Dawn Spot Volatility[23]

A growing number of natural gas pipeline projects at Dawn are expected to expand market area gas supply in Ontario and provide downward pressure on natural gas prices. Several projects currently under construction involve additions of pipeline to bring Marcellus and Utica shale gas to the Dawn Hub.

Though low and stable natural gas prices are generally anticipated to persist at the Dawn Hub due in part to the continued abundance of North American natural gas supplies and new pipeline infrastructure in the Dawn area, there continues to be uncertainty as to natural gas pricing going forward, and there are no guarantees as to absolute price levels or volatility in pricing.

Changes in the market can occur quickly and unexpectedly. The recent shale gas boom in North America serves as a prime example of unforeseen market effects – abundant

[23] Volatility is calculated as the yearly standard deviation of the log-return of prices.

shale gas supplies flooding the market and depressing prices. Despite new pipeline infrastructure expanding supply, the exportation of LNG to foreign countries could cause prices to rise. With spot prices in Europe and Asia in the first half of 2013 just below the US$20/MMBtu, exporting LNG would offer North American producers substantial profits. Currently, sixteen companies await export license approval from the Department of Energy of the United States. One LNG export terminal project, Cheniere Energy's Sabine Pass in Louisiana, has already received a license and could begin exporting gas abroad by 2015. In addition, there are five proposed LNG export facilities proposed in Canada – four on the west coast of Canada and one in Atlantic Canada. Currently there is concern in the U.S. regarding the export of significant volumes of LNG due to the effect that such large exports could have on domestic natural gas prices.

Because natural gas pricing at Dawn is interrelated to the broader North American natural gas market, depending on the number and size of these LNG export projects that move forward, Dawn could experience higher and/or more volatile natural gas prices going forward. In addition, another significant potential driver of increased natural gas demand going forward is the potential retirement of coal-fired generation in the U.S., primarily in the Midwest and Appalachian regions, as a result of more stringent environmental regulations.

Due to this kind of uncertainty, projections of natural gas pricing and volatility should not be taken as guarantees of a future outcome, but rather should be considered in making any natural gas purchasing decisions. Forecasts are calculations or predictions of some future event or condition based on the analysis of available, pertinent data. They extrapolate current trends into predictions about the future. No matter how scientific the methodology, forecast accuracy can never be guaranteed. Rather, predicting is an imprecise process that relies upon probability. Uncertainty cannot be fully taken into account, and thus, it is important to undertake a reasonable and appropriate hedging plan to provide protection against future uncertainty.

Q59. IS DAWN A GOOD PRICING POINT TO EXECUTE THE RISK MANAGEMENT STRATEGY?

A59. No. Dawn is a liquid hub for spot gas (i.e. short-term delivery), but not a good pricing point to execute a hedging strategy. Dawn is not favored by counterparts as a hedging point and it is largely overwhelmed by hedging based on Western Canada prices. The Chicago Mercantile Exchange clears a contract to hedge at Dawn that theoretically allows for hedging 36 months into the future, but the activity is extremely limited. The reported open interest[24] is non-existent for the 36 month curve as of May 3, 2013. There is some trading activity in over-the-counter markets that allow for some price discovery, but no verifiable volumetric statistics.

Trading activity over the past year in over-the-counter forward curves[25] shows that the price patterns of AECO and Dawn are converging (see for instance July 2013 trading activity in Figure 9). Since AECO is a liquid point, financial traders will typically tend to favor hedging exposures at Dawn by hedging AECO instead.

[24] Open interest represents the total number of contracts either long or short that have been entered into and not yet offset by delivery.

[25] Quotes are available from OTC Global Holdings (http://www.otcgh.com). OTCGH is an independent inter-dealer broker in over-the-counter energy commodities.

Figure 9: Dawn Vs. AECO Forward Prices for July 2013

Source: Concentric Energy Advisors using data from OTCGH

VIII. ***C**ONCLUSION*

Q60. SHOULD THE PROGRAM CONTINUE?

A60. Yes, but under a reformulated set of protocols and strategies.

Q61. WHAT WOULD BE THE CONSEQUENCES OF ELIMINATING THE PROGRAM?

A61. I would not recommend it because the absence of some sort of hedging program eliminates the ability to protect against natural gas price spikes.

Q62. ARE THE INTERVENERS YOU INTERVIEWED INTERESTED IN ELIMINATING THE PROGRAM?

A62. I don't believe they are. The conversation with the interveners leads us to conclude that there is a consensus on the existence of some Program to provide price protection for the captive ratepayers, i.e. the minimum cost price protection that protects against extreme price spikes. At least one intervener expressed skepticism that price protection was actually being passed on to the majority of low-income users, since energy pricing depends on landlords and the rent control board (Régie du logement). A summary of the aggregate findings of the interviews with the interveners is included in Appendix D.

Q63. ARE THERE ENHANCEMENTS THAT YOU WOULD RECOMMEND TO THE PROGRAM?

A63. The items identified in the evaluation of the Program naturally flow into a series of elements recommended to enhance the Program: awareness, measurement and decision making based on riskThese three elements are directly aligned with the Régie’s concerns and with best industry practices. At the heart of this philosophy is a perspective on risk that is a two-fold proposition. The cost/benefit of the Program should reflect a balanced perspective of both upside and downside exposure.

- Concern for Prices Increasing (Upside Exposure or Budget Risk) - Fixing the price of fuel well in advance creates budget certainty and avoids prices “higher than today”. The activity under the current Program is clear evidence that this is the primary concern driving the hedging activity;
- Concern for Prices Decreasing (Downside Exposure or Prudence Risk) - Fixing the price of fuel in advance of delivery creates the possibility of having fixed an expensive price when compared to the alternative of purchasing the fuel in the spot market;
- Reconciled Exposure to Prices Increasing and Decreasing. This reconciliation of the upside and downside risks also provides a perspective as to how far out to hedge, when to hedge, how much to hedge and at what prices to hedge, while it concurrently addresses the need to remain competitive. Operationally, this approach takes into account the joint assessment of upside and downside exposure and arrives at a recommended hedged volume based on the two forces “pulling” to hedge or not to hedge.

The balanced approach also relies on another element of the ability to measure risk. Notwithstanding known deficiencies, best practices are still described by characterizing risk as a function of Value at Risk (VaR). VaR was originally developed to characterize only one potential movement (either up or down) because it was originally developed for trading environments that only have exposure when buying or selling a position. The application of the technique to an end-user (like Gaz Métro) simply extends the measurement to both possibilities (up or down).

Q64. COULD YOU SUMMARIZE THE ENHANCEMENTS TO THE PROGRAM?

A64. The suggested enhancements to the Program are based on two protocols: Programmatic and Defensive. The recommended parameters of this strategy are as follows:

- The programmatic protocol will continue to work in a very similar fashion as the current Program but will be executed between 12 and 24 months before the expiration of the contract and built up to a 20 percent hedged position in equal monthly increments between 12 and 24 months before expiration of the contract and will use both fixed-price instruments and costless collars.
- The defensive protocol will be in addition to the programmatic protocol and will be executed within 12 months before the expiration of the contract and for an incremental amount not to exceed 50 percent. The evaluation of the volatility of the market will be done eight times per year in the context of the existing structure of meetings by the multisector committee. The evaluation of the risk exposure will be done using market prices and volatilities as of the week prior to the meeting and will allow the use of fixed-price instruments (i.e. swaps) and costless collars.
- The targeted hedge percentage in aggregate should not exceed 75% of expected requirements to ensure there is flexibility for variation in required volumes.

Q65. HOW WILL THE PROGRAMMATIC PROTOCOL BE IMPLEMENTED?

A65. Hedging under this Protocol implies that a targeted hedged position of 20% in total per month will be achieved by incrementally hedging 1/12th of that target on a monthly basis between 12 and 24 months before the expiration of the contract. Programmatic hedges (i.e. time-based triggers) should not be ruled out, but they should not be the dominant feature of the Program. A protocol that takes into account the market conditions (i.e. defensive hedges) should have the larger role.

Take for instance the hedging activity for July 2015 expiration, which is 25 months before expiration as of the writing of this analysis. According to the logic specific above, the hedges will build incrementally every month (dark blue portion of the bars in Figure 10) to a cumulative position indicated by the light-shaded bar chart. Every month beginning June 2013, a small portion is increased to hedging activity as time progresses, so that by May 2014 we will have already covered 20% for this particular month.

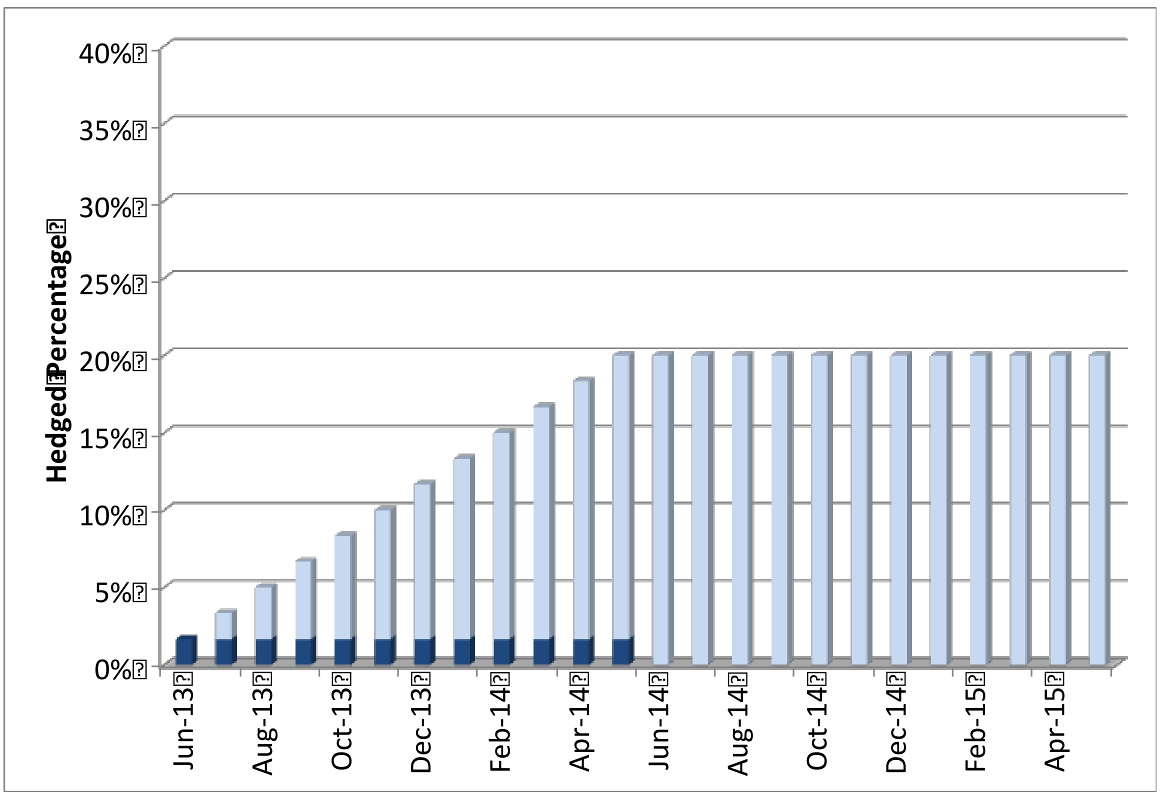

Figure 10: Illustrative Evolution of Hedges for July 2015 Expiration under Programmatic Protocol

Q66. HOW WILL THE DEFENSIVE PROTOCOLS BE IMPLEMENTED?

A66. The defensive protocol is incremental to the programmatic protocol and will be executed between one and 12 months before the expiration of the contract. The amount to hedge will be dictated by how the risk exposure encroaches on the tolerance to hedge and in the proportion indicated by the equation in A53.

Following-up with the example in A67, the June 2015 requirements will be hedged 20% by May 2014. Let's assume that the weighted average hedged price for June 2015 by May 2014 is $4.00/MMBtu for a total of 20% and that the market price is $4.50/MMBtu. The hedge in this illustration is favorable by $0.50/MMBtu but the June 2015 contract has already "created" a potential opportunity cost by the possibility that prices for this contract may continue to evolve (still has a year of life) and expire below $4.00/MMBtu (let's assume that if prices decrease they could settle at $3.50/MMBtu). Alternatively, just as there is risk of prices decreasing there is risk of prices increasing. Assume for now tht if prices increase they could settle at $6.00/MMBtu at expiration. Under this scenario, the market has a price exposure of $1.50/MMBtu to the upside from the current market. Since there is already a 20% hedge at $4.00, the downside exposure is only for the hedged portion, and the upside exposure is only for that portion that has not been hedged.

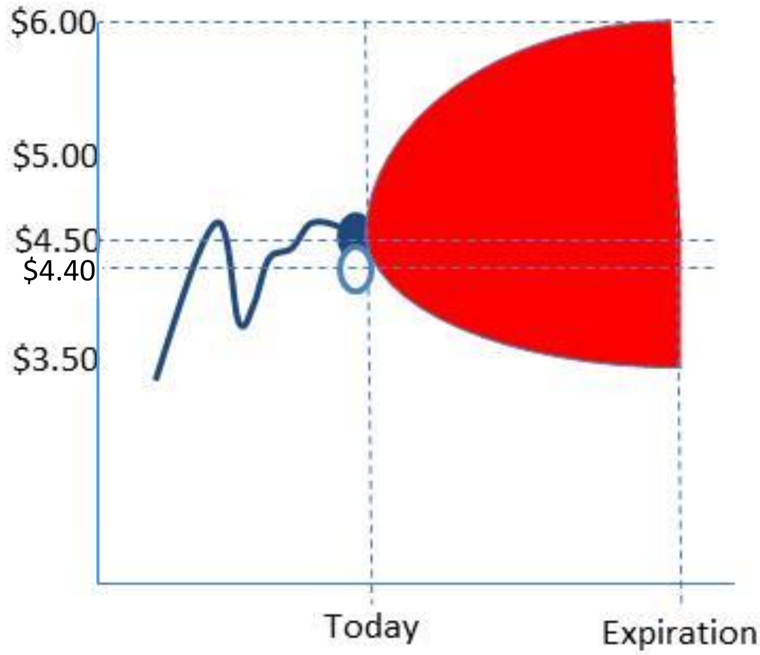

Figure 11: Illustrative Exposure Addressed by Defensive Protocol

Under this illustrative scenario, the defensive protocol will recommend a hedge if the exposure (highlighted by the red cone in Figure 11) is beyond tolerance (either downside or upside). Please note that increasing hedges at market ($4.50) will increase the impact of the opportunity cost because prices may decrase, but will curtail the impact of price increases. This "choice" of hedging to protect upside while creating downside exposure by hedging is at the heart of the decision making process of every hedging activity.

We now need to make an incremental assumption of the tolerance to risk and assume that the upside tolerance is established at $5.00/MMBtu and the downside tolerance (or the tolerable opportunity cost) is $1.00/MMBtu. As Figure 12 indicates, the potential exposure on the upside is in excess of the tolerance and the downside tolerance is marginally above the limit[26].

[26] Porfolio price before any defensive hedges take place is $ 4.40/MMBtu or 20% at $4.00 and 80% at $4.50

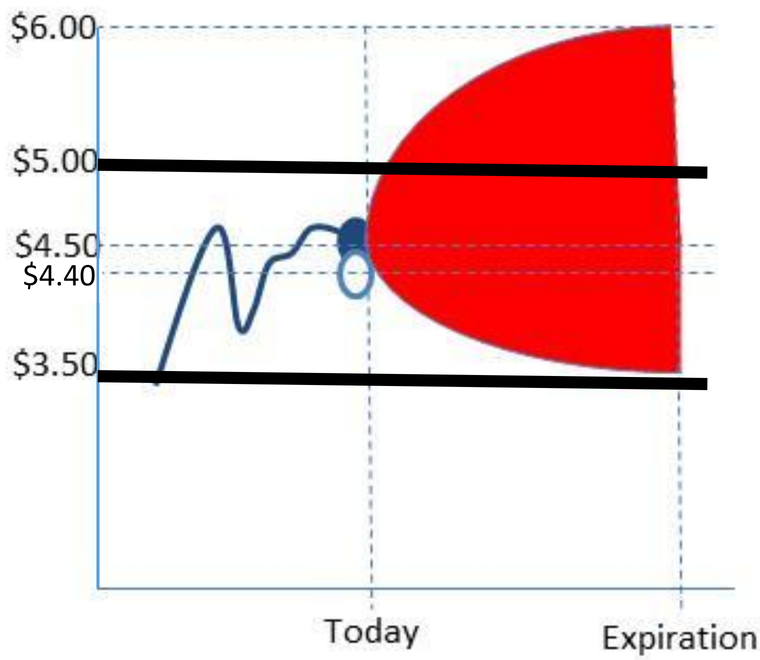

Figure 12: Illustrative Exposure Addressed by Defensive Protocol and Tolerances

Let's assume that we are only concerned with upside exposure. The potential exposure is $1.50/MMBtu above current market, but since we already have 20% hedged (under the programmatic protocol) we are only faced with 80% of $1.50/MMBtu or $1.120/MMBtu. If the market price evolves according to the exposure highlighted by the upside risk, we could end up paying $5.60/MMBtu[27] and this would be in excess of our tolerance of $5.00/MMBtu by $0.40/MMBtu. We need to hedge "enough" so that the maximum price under the upside risk scenario is back to $5.00/MMBtu or an incremental 24%.[28]

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[27] $5.60=20% at $4.00 from Programmatic hedges and 80% at $6.00 which is the market upside risk. $6.00 – 0.20 * ($6.00 - $4.00) = $5.60

[28] We need to incrementally hedge 40% to have a weighted average cost of $5.00 in alignment with the upside tolerance. 5.00=(20%*$4.00)+(40%*$4.50)+(40%*6.00). Since the balancing factor indicates 60% concern for upside risk and there is no encroachment on downside exposure, then the total incremental hedge is 24% (40%*60%) for a cumulative hedge of 44% (20% from Programmatic and 24% from Defensive).

Let's ignore for now the amount to hedge to protect upside exposure and concentrate on downside exposure to find out how much hedge we need to avoid to remain within the downside tolerance. From previous assumptions, we have stated that the programmatic protocol hedged a price of $4.00/MMBtu for 20%. Hedging the remaining 80% at current market would yield a portfolio price of $4.40 , If we fully hedge at current market and the market settles at $3.50/MMBtu the opportunity cost would be $0.90/MMBtu[29] which is less than the $1.00/MMBtu tolerance established in the assumption. We therefore do not need to avoid any hedges at this time.

In this particular case the cumulative hedge: 24% from Defensive protocol and the pre-existing 20% from programmatic hedges. This incorporates the assumption that the "appetite" for upside risk is marginally higher than the concern for downside risk (60/40[30]).

Q67. CAN THIS PROCESS BE IMPLEMENTED?

A67. This process has a very unique feature in that all of the logic is based on an algebraic solution that can be implemented in an MS-Excel® spreadsheet and the results can be audited. Once the formulas are calculated and the parameters for risk tolerance are established, the process can be automated fairly easily. It provides an objective, methodical and quantitative way to take into account current market conditions as key drivers to the hedging decisions. Hedging activity will take place only if the risk encroaches on the tolerance and in as much as the opportunity cost is not breached.

In the example, assume that risk can be estimated and this can actually be done with established statistical methodologies that can also be programmed into a spreadsheet. It simply takes the basic theory of confidence intervals and applies it to the potential

[29] 0.20 * ($3.50 - $4.00) + (1 – 0.20) * (3.50 – 4.50) = -$0.90

[30] This means that concern for upside exposure is marginally higher than for downside exposure. A balancing factor of 50/50 would imply an equal concern for upside and downside exposure

movement of prices from current market levels. It may take some time to get familiar with the formulas, but the mathematics are straightforward.

Q68. HOW DO YOU DEAL WITH THE PARAMETERS OF RISK TOLERANCE?

A68. As you can tell from the calculations, the mechanics to estimate risk and the amount to hedge are simple algebraic relationships or statistical estimates. The key element is to define tolerances (upside and downside) that are meaningful to customers. In my experience, defining the tolerance is probably the most meaningful part of risk management and truly connects the hedging to a meaningful business process. It transforms a risk exposure into a management decision, with stakeholders' input.

I nevertheless recommend a default strategy to determine the tolerance for risk and the balance of risk based on my prior experience helping clients define these elements. The tolerance can be established by taking into account forward market prices for the month entering the defensive hedge horizon and assuming a very wide potential movement of 99%.

Let's assume that we are starting June 2013 and the July 2014 contract is just entering the 12-month hedge horizon specified in the defensive protocol. At this point, Gaz Métro will estimate the volatility of that contract to expiration based on a 99% confidence level and use this as a guideline for a reasonable tolerance level.

I recommend to set the balance between upside and downside risk exposure at 60% upside and 40% downside to reflect the skewed nature of natural gas prices that tend" to move further away from the mean on the upside than on the downside.

Q69. HAVE YOU HAD A CHANCE TO DISCUSS THIS PROCESS WITH GAZ MÉTRO?

A69. Yes. I have presented this process to Gaz Métro and highlighted the mechanics of how to implement it, and I am confident the Company's staff can implement this model. I recommend a hands-on workshop with Gaz Métro staff to guide the process. I suggest the Régie address the staff from Gaz Métro as to their comfort level with this process.

Q70. WHAT IS THE BASIS FOR RECOMMENDING THESE CHANGES AND PARAMETERS?

A70. It is a combination of my professional experience and an extensive analysis to understand how this kind of enhanced strategy might have performed in the past and the likely performance in the future. The analysis to recreate the past is called "Backcast" and the analysis to simulate the future is referred to as "Monte Carlo" given the name of the statistical technique at the heart of the analysis.

Q71. SUMMARIZE THE PARAMETERS THAT YOU SELECTED AND THE SUMMARY RESULTS OF HOW THIS STRATEGY COULD HAVE PERFORMED?

A71. The key parameters are as follows:

- Hedge horizon: 24 months
- Programmatic: 20% of expected needs executed for 12 months starting 24 months before expiration
- Defensive: Not to exceed 50% of expect needs executed for 12 months starting 12 months before the expiration of the contracts
- Instruments: Fixed price positions and costless collars for both programmatic protocols and fixed positions, costless collars and synthetic calls for defensive protocols.
- Risk Tolerances: I am suggesting basing the tolerance on a formulaic statistical expectation based on what prices are at the time rates are reviewed. This statistical expectation of the tolerance therefore becomes the reference point for the Regie's decision on the final risk tolerance.

- At least 30% is unhedged. The cumulative 70% maximum hedge is based on historical variability of expected natural gas needs.

Q72. HOW WOULD THIS PROPOSED STRATEGY COMPARE TO HISTORICAL OPPORTUNITY COST?

A72. The simplest way to understand the comparative performance is by plotting the actual opportunity cost (Figure 1) versus the results of applying the strategy to the same price series (Figure 13). On the aggregate, the figure shows a smaller opportunity cost.

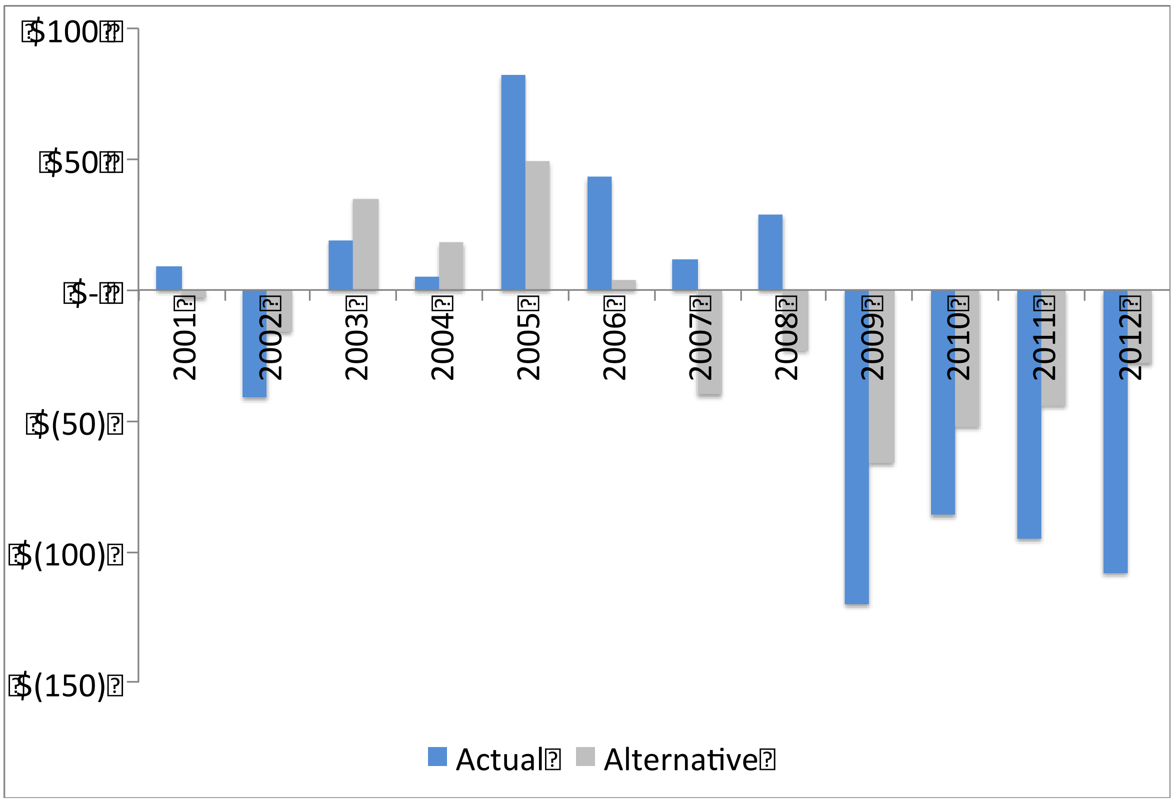

Figure 13: Comparative Opportunity Cost (Historical Vs. Simulation of Proposed Strategy

The statistical work done to arrive at these results involved testing numerous scenarios to uncover an adequate combination. This meant simulating the opportunity cost by changing parameters such as hedge horizon, total amount to hedge, tolerance levels, instruments, percentage to hedge, percentage under programmatic, percentage under defensive, and price levels for collars, among others. All in all we simulated more than 150 unique combinations based on the historical price series.

A second approach to enhance the statistical significance of the backcast was to simulate more than 30 different ways in which the historical figures could have evolved in the past. While it is true that the actual history is useful and undeniable, testing how history could have evolved under separate assumptions increases the statistical significance that provides a certain degree of comfort as to how the strategy could have performed under different scenarios.

This second approach increases the robustness of the analysis by making up alternative historical prices to provide a better understanding of potential opportunity costs. Instead of just one series for historical prices there is now a set of potential historical prices that each yields a different opportunity cost.

A third and final statistical approach was performed that instead of recreating the historical prices based on alternative scenarios, created 20 different potential scenarios of the future starting with January 1, 2014.

The selected parameters (as highlighted above) were the ones that best met the following criteria according to the five statistical metrics highlighted above:

- Low total opportunity cost (sum) over the period
- Low single-year opportunity cost over the period
- Low aggregate variation in the opportunity cost (standard deviation)
- Low hedged cost31 (average) over the period
- Low aggregate variation of hedged cost (standard deviation)

The detail of the analysis is available upon request.

[31] Hedged cost is understood as the price achieved through the hedging activity and the unhedged portion purchased at market settlement.

Q73. WHAT KIND OF PERFORMANCE CAN WE EXPECT FROM THIS STRATEGY IN THE FUTURE

A73. The historical results should provide an idea as to how it is likely to perform, but it is possible to try to create a "reasonable" picture of how prices may evolve in the future according to the statistical technique called Monte Carlo where potential prices (or paths) are created based on reasonable assumptions of volatility and how prices "migrate" in time. It is also reasonable to expect that this "path" is one of many possible paths that prices may follow and to achieve this we created a series of 20 potential different paths according to the Monte Carlo technique outlined above.

Just as we tested how the strategy would have performed using actual prices, we proceeded to recreate a performance metric for each of the 20 price paths and averaged the performance in terms of a distribution of prices as projected on a daily basis for 2014, 2015, 2016, 2017 and 2018. We then proceeded to associate the average opportunity cost with the average natural gas price scenario to arrive at Figure 14.

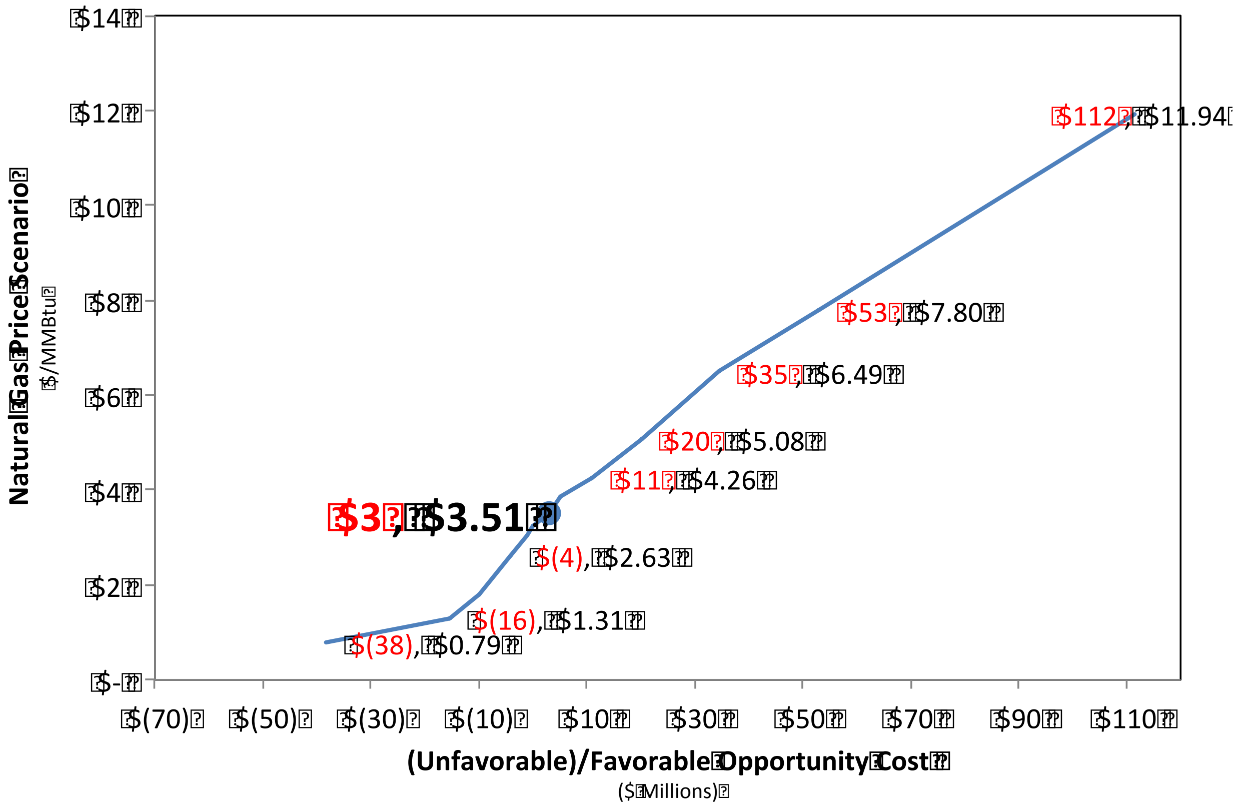

Figure 14: Expected Performance of the Hedging Strategy

The price/opportunity cost relationship portrayed in Figure 14 is derived based on the likelihood of both prices and opportunity cost. For instance, the natural gas scenario of \$3.00 / MMBtu and the \$3.51 millions of opportunity cost are associated with the 50th percentile of the respective distributions. These results should be interpreted as an "expected" performance and not as a guarantee of results.

If you are considering reactivating the hedging strategy "soon" this will likely impact the future performance of the hedging program because natural gas prices are "low" and it is hard to envision that current market prices will drop as dramatically as they did since 2009.

Q74. CAN THIS STRATEGY BE APPLIED TO A PORTION OF THE LOAD, OR ALTERNATIVELY, CAN THIS STRATEGY BE BROKEN DOWN INTO DIFFERENT GROUPS TO ALIGN WITH DIFFERENT TOLERANCES FOR RISK?

A74. I do not recommend it. While it is tempting to segment the strategy to better align with perceived difference in risk tolerance, I recommend focusing on implementing a program for the entire load that aligns with the objectives of diminishing the likelihood of price spikes and creates rate stability. The hedging strategy I am recommending is based on the three core premises that align with all types of risk profiles: awareness, measurement, and decision making based on risk. Instead of trying to break up the Program into several pieces to align with different risk tolerances, I recommend increasing the understanding of the Program and therefore enhancing its value to customers. Based on my previous experience, some of the specific reasons to maintain the unity of the Program are as follows:

- Transcient Perception of Risk. In my experience the perception of risk tolerance may change as a function of many items that affect a particular customer. A Program that tries to accommodate for different risk tolerances sets itself up to exposure to chasing tolerances as they are perceived to change;
- Administrative Expense Increases. The amount of time spent trying to understand, update and react to disparate perceptions of risk tolerances makes administering the Program very cumbersome. It also increases the complexity of evaluating the benefits of the Program;
- Reduces the Aggregate Efficiency of the Program. As/if the Program reacts to disparate risk tolerances it also reduces its ability for the Program to mature in its results, hedge horizon and performance metrics. A Program that is implemented to differing risk tolerance may end up changing tactics along the way; and
- Unbanced Comparisons. Having a Program that aligns to several risk profiles may lead to unfair comparison of performance metrics and may, in turn, lead to further segmentation of the Program.

Q75. CAN THE RÉGIE BE ASSURED THAT THE RECOMMENDED ENCHANCEMENTS WILL YIELD MORE REASONABLE OPPORTUNITY COSTS?

A75. The recommendations I am making are based on my knowledge of best practices and directly address the concern to be more adaptive to current market conditions. The enhancements also create a metric that is more useful to execute the risk management strategy and provides an auditable trail to gauge the performance of the execution. The enhancements address protection against price spikes and stability in prices by purposefully addressing the risk of prices increasing and decreasing.

These enhancements nevertheless do not guarantee that the Program will perform better than the market, it simply increases the probability that desirable results will be achieved in relation to the objectives. No program design can guarantee consistently above average results; believing a strategy can actually provide guaranteed results is speculative and unrealistic. No strategy (or the elimination of the Program) creates the risk that prices will rise and that customers will not have a mechanism to protect against these rises. The strategy of no strategy is therefore inferior to a strategy that is aware, measures and makes decisions based on risk exposure.

Q76. BASED ON THE CURRENT HEDGED POSITION FOR CONTRACTS THAT HAVE NOT EXPIRED, WHAT CAN WE EXPECT TO SEE AS INCREMENTAL OPPORTUNITY COST?

A76. Gaz Métro has hedged positions through October 2015 averaging 27% with a total unfavorable mark-to-market (i.e. opportunity cost) of $11,066,853 as of April 30th 2013 (Figure 15).

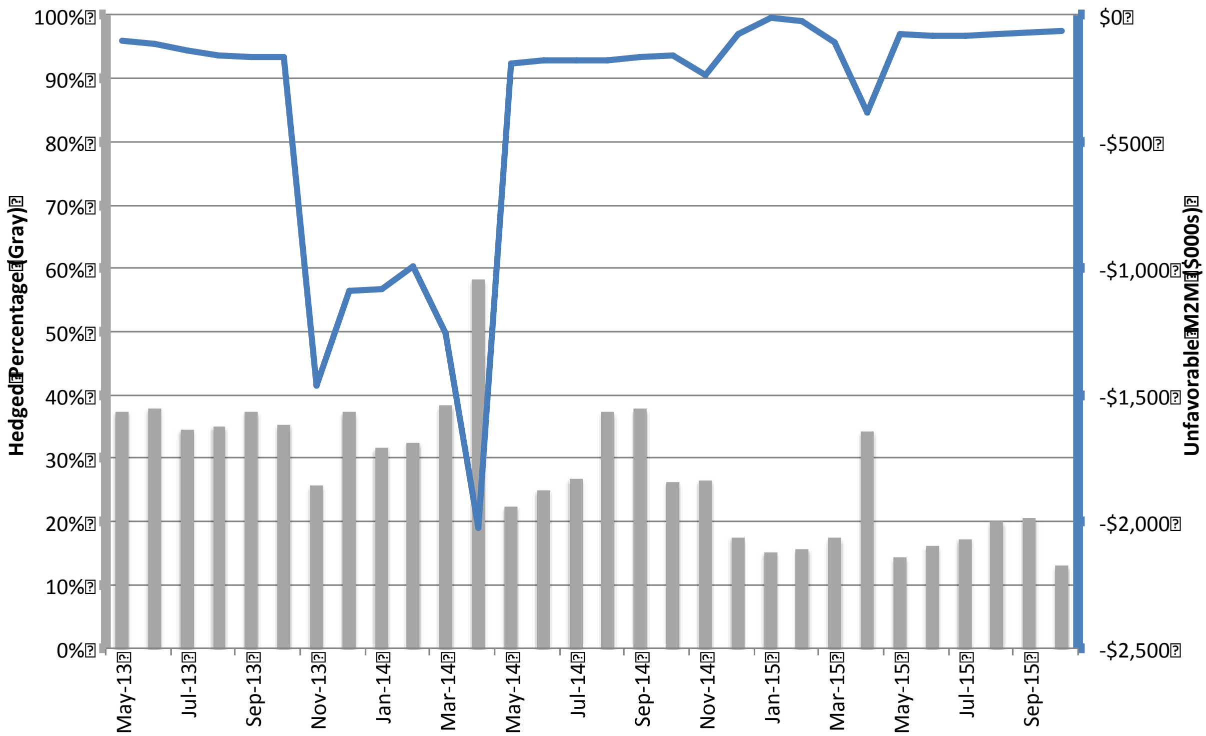

Figure 15: Hedged Position (gray, left) and MTM (blue, right) as of April 30, 2013

Q77. GAZ MÉTRO ALREADY HAS A HEDGED POSITION THAT EXCEEDS THE RECOMMENDED PARAMETERS OF THE ENHANCEMENTS TO THE PROGRAM. HOW WILL THE PROGRAMMATIC PROTOCOL BE EXECUTED MOVING FORWARD?

A77. Almost all of the months showing existing hedges are in excess of the preliminary estimate of 20% for the programmatic protocol. Assuming no pre-existing hedges in place, hedging activity under this protocol will start during the month of June 2013 by hedging about 1/12th of 20% (1.67% of the rounded equivalent that is feasible to hedge) of the estimated requirements for July 2015 (the contract that would be 24 months into the future). A month after that (i.e. during July 2013) Gaz Métro will hedge an incremental 2.08% of the estimated requirements for July 2015 and 1/12th of 25% (2.08%) of the estimated requirements for the month that just rolled into the 24 month hedge horizon (August 2015). Under this logic, Gaz Métro will build hedges for individual months so that 12 months before expiration of the contract, 20% of the total hedged position will be covered under this protocol.

Since there are already hedges in place, the existing hedged position will increase in accordance with the protocol starting point. For instance, December 2014 is 19 months into the future, and, according to the proposed protocol, should have accumulated 10% but already has an 18% hedged position. Instead of starting to hedge December 2014 needs in June 2013, hedging activity for December 2014 would start in February 2014. The 18% hedged position is equivalent to about nine months of prescriptive hedging under this protocol.

Q78. WHAT DO YOU RECOMMEND REGARDING THE EXISTING HEDGED POSITIONS THAT ARE UNFAVORABLE TO CURRENT MARKET PRICES?

A78. I recommend keeping them. In general utilities typically do not liquidate hedges before expiration to mitigate a loss because it would monetize a paper loss that could eventually disappear.

Q79. ARE THERE OTHER PROTOCOLS THAT COULD BE ACHIEVED INSTEAD OF THE DEFENSIVE AND PROGRAMMATIC PROTOCOLS?

A79. Yes. The two protocols outlined above (defensive and programmatic) imply an active process of awareness, measurement and decision making to avoid an undesirable risk exposure. A more passive protocol to consider is to simply buy insurance" upfront against significant price spike. This protocol is characterized by purchasing insurance materially above current market prices (i.e. out-of-the-money call options) to protect consumers against upside exposure. For instance, assume that natural gas prices are $4.00/MMBtu. Gaz Métro could purchase an option at $5.50/MMBtu (well out-of-the-money) and ensure that the customers will not be affected by prices in excess of the contracted level. If market prices do not settle above the $5.50/MMBtu, Gaz Métro will purchase at whatever the actual market price may be and pass along the savings to the customer.

To achieve this, Gaz Métro would have to pay (upfront) an estimated premium of $20 million per year[32]. This protocol is very similar to automotive insurance where a premium is paid upfront, the consumer has some form of a deductible, the insurance company would pay beyond a certain point and (very likely) the insurance company will provide a maximum payment (to limit their exposure).

The benefit of this protocol is that it has no downside exposure, other than the premium paid up-front. The opportunity cost highlighted by the Régie would not apply to this protocol because the cost in excess of the market would be known and capped at the time the insurance is purchased.

The downside of the protocol is threefold: it requires a premium paid up-front, the price level to buy insurance remains a decision point and the premium may be significant. To hedge the volume for system gas, Gaz Métro would have to pay (upfront), and the near-term impact to rates would be very significant.

The premium is calculated as a function of three factors: volatility, the difference between current market prices and the price at which insurance is purchased (the strike price), and the time to expiration. The impact of these variables is highlighted in the following Figures. Figure 16 shows how the price of the insurance (as a percentage of the price of the commodity) increases as the time to expiration increases (everything else kept constant). Figure 17 shows how the price of insurance (as a percentage of the price of the commodity) increases as the volatility increases (everything else kept constant); and Figure 18 shows how the price of the insurance decreases as the price trigger for insurance (strike price) increases and the probability of needing the insurance decreases (everything else kept constant).

[32] Assumes system gas volumes of 61 Bcf per year, market price of $3.50/Mcf, volatility of 35% per year and a premium for the option of approximately 10% of the value of the underlying.

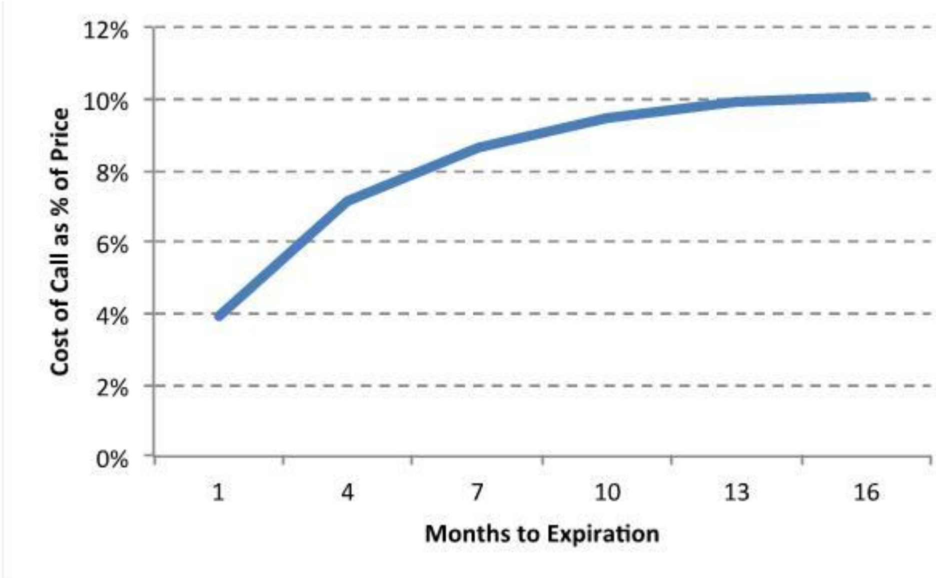

Figure 16: Cost of Call As % of Price of Future Increasing the Time to Expiration

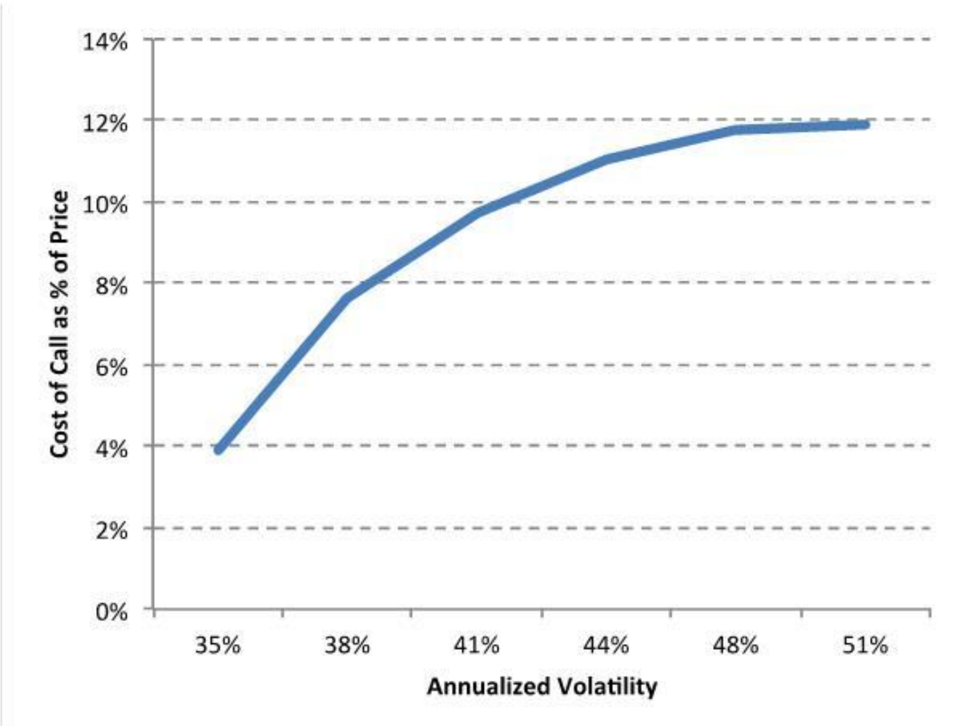

Figure 17: Cost of Call As % of Price of Future Increasing Volatility

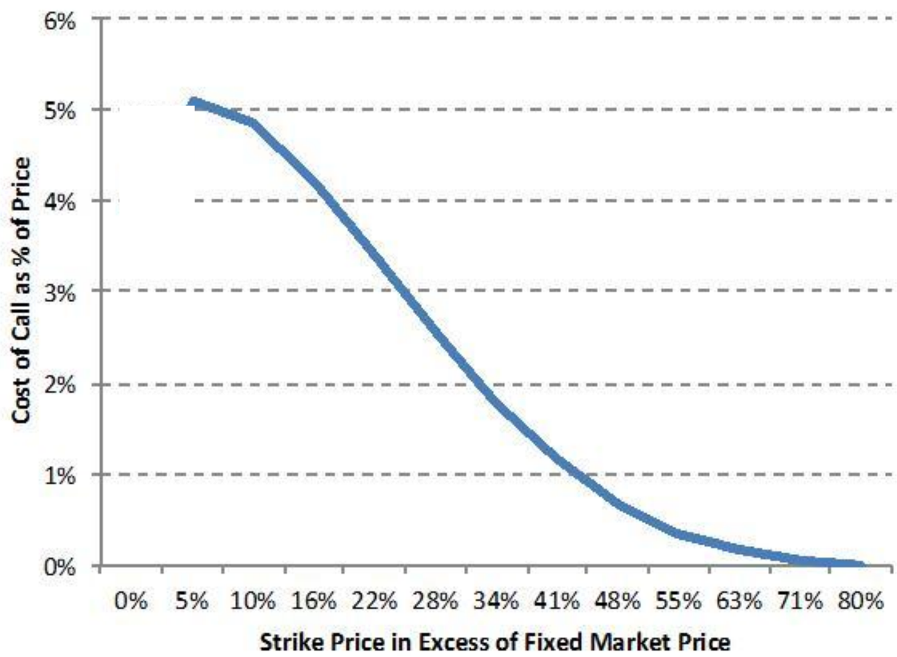

Figure 18: Cost of Call With Increasing Strike Prices

Purchasing insurance without some mechanism to offset the cost or to finance the cost upfront is problematic, especially when the term of the insurance goes far out into the future, when the volatility increases and when the strike price of the insurance is closer to current market prices (increases the chance of cashing in on the insurance).[33] Purchasing insurance therefore seems like an obvious choice, but the cost (especially in the near term) may make it prohibitive.

Q80. DOES THIS CONCLUDE YOUR TECHNICAL ANALYSIS?

A80. Yes

[33] Options values are calculated using Black-Scholles (1976) option pricing model and should therefore be treated as indicative. The liquidity of options is significantly lower than for fixed-price financial instruments and the price of insurance may change substantially upon execution or when liquidated in advance of expiration.

IX. *APPENDIX A – RESUME*

Ruben Moreno has been helping large consumers or producers of energy optimize expenditures, revenues and investments for the past 19+ years in the US, Canada and South America. He is a specialist in environmental security, risk management, quantitative methods and statistical analysis. He has advised on the exposures of a US$10 billion portfolio and also has broad experience in management consulting and teaching. His experience includes a broad range of fuels (oil, natural gas, coal, wind, solar and hydro), differing generating technologies and extensive transactional experience supporting clients design and implement energy procurement practices to identify how much to purchase, when and why.

Representative Project Experience

Expert Witness

- Evaluated Nova Scotia Power Inc. (NSPI) hedging strategy and provided expert witness testimony on behalf of NSPI before the Nova Scotia Utility and Review Board (NSUARB) under Docket M04972). An audit conducted on behalf of the NSUARB recommended the deferral of $12.8 million due to NSPI's alleged failure to hedge Northeast Market basis during the Winter 2010-2011. On December 21, 2012, the NSUARB published its decision on the case (2012 NSUARB 227) ruling that NSPI was able to recover the full $12.8 million.
- Evaluated Guam Power Authority's (GPA)'s energy risk management program in light of unfavorable financial hedge settlements of $64 million. Wrote report and presented a defense before Guam's Public Utility Commission and its consultant.

Asset Valuation

- Designed, valued, supervised and implemented market transactions for more than 40 GW of generation/load and the associated fuels;

- Created a risk-based analytical framework to evaluate the value of a power plant and negotiated the value on behalf of the customer. Final result avoided 40% increase in the cost of operating the plant;
- Audited the risk management function of Powerex (wholesale energy trader in Canada) on behalf of its (regulated) owner BC Hydro. Involved the evaluation of VaR calculation and portfolio aggregation;
- Asset Valuation and Risk Management Strategy to enhance/protect the value of a power-generating asset in bankruptcy from the perspective of the holder of a long-term energy contract;
- Risk Profiling of Operational Risk Exposures for Industrials and Power Producers in Mexico, Canada, Europe and the U.S.; and
- Designed and implemented risk management and value-extraction derivative structures to meet corporate objectives within a manageable (i.e. acceptable) risk profile. Market Risk Management

<u>Market Risk Management</u>

- Designed, valued, supervised and implemented market transactions for more than 40 GW of generation/load and the associated fuels;
- Created a risk-based analytical framework to evaluate the value of a power plant and negotiated the value on behalf of the customer. Final result avoided 40% increase in the cost of operating the plant;
- Audited the risk management function of Powerex (wholesale energy trader in Canada) on behalf of its (regulated) owner BC Hydro. Involved the evaluation of VaR calculation and portfolio aggregation;
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- Risk Profiling of Operational Risk Exposures for Industrials and Power Producers in Mexico, Canada, Europe and the U.S.; and

- Designed and implemented risk management and value-extraction derivative structures to meet corporate objectives within a manageable (i.e. acceptable) risk profile.

Compliance to Accounting Standards

- Designed, implemented and audited compliance to standards for regulated and unregulated energy companies;
- Conceptualized, systematized and implemented ad-hoc comprehensive risk management metrics for government clients in pursuit of compliance to constituent's expectations;
- Commercial assistance to customers to interpret and implement the newly adopted Federal Accounting Standard to determine Fair Value of derivative products (FAS-157);
- Commercial assistance to support hedge efficiency standards under the Federal Accounting Standards for the registry of derivative products (FAS-133(7)); and
- Audited entire risk management and compliance functions for regulated utilities.

Operational Risk Management

- Designed, implemented and audited policies, procedures and programs to avert non-compliance to standards or business goals;
- Created essential risk reporting position report to inform client on the risk exposure and its management;
- Trained 20+ project managers on risk management principals and how to apply them to project management and budget protection;
- Risk Management Strategy (structuring and implementation) to protect the Cost of Service expectation (i.e. Budget) for Energy for a $623m portfolio;
- Lead expert and project manager in risk quantification, measurement and integration or a risk management function and compliance function on behalf of consulting companies (R.W. Beck, SAIC and Pace Global) and regulated utilities (e.g. NYPA, LIPA, Santee Cooper, CDWR);
- Responsible for risk management practice that supports a $10 billion portfolio of different projects;

- Created and managed a business practice that has allowed my staff to achieve above average salary growth rates YOY;
- Supervised eight analytical staff and help them translate quantitative work into products that are sellable and valuable to the client; and
- Created, managed and presented weekly publication distributed to large industrials and power producer on Operational Risks affecting the Energy industry.

<u>Enterprise Risk Management</u>

- Designed, implemented and audited enterprise risk management functions and insurance structures;
- Designed and implemented the enterprise risk management for a large generation and transmission company in the Colorado Area. The assignment included creating a framework for understanding and measuring the risk, identifying a plan forward on how to implemented and the design of a set of executive-level reporting structure;
- Evaluated the aggregate risk exposure for a large transmission, distribution and generation company in South California and identified all aspects that may generate a legal implication; and
- Evaluated the insurance adequacy associated with operational and market exposure. The analysis evaluated a tiered approach to the acquisition of insurance and a comparison with cost of money to determine self-insurance levels.

<u>Transactional Experience</u>

- Designed and implemented market-specific transactions;
- Assisted a purchaser of debt from distressed assets with an option for converting to equity (debtquity). The analysis identified generic market areas and identified opportunities to purchased distressed debt assets;
- Advised customer on $75M pre-payment of natural gas and heating oil contracts and participation to softer energy prices on behalf of customer;
- Assisted energy producers and buyers to structure, formulate, bid, qualify and negotiate energy structures to satisfy a business requirement within a risk management context; and

- Evaluation and enhancement of the risk management function of a major utility in the Northeast from the point of view of the takers of 25% of the total output.

Statistics and Load Growth

- Expert-level statistic practitioner with the ability to translate the impact of energy load growth and energy-specific risks to the demographics.
- Assisted multiple clients to statistically characterize their growth in energy use, design strategies to supply that growth typically in a long-term scenario (30-year strategic energy plans).
- Technical expert in productivity measurement and cross-industry comparisons.
- Assisted the City of Quincy Florida to understand the behavioral impact in the deployment of smart grid technology and how to best implement in the context of very specific demographic constraints.

Finance and Budget Analysis

- Technical expert in finance at the operational, academic and strategic level.
- Asset Valuation and Risk Management Strategy to enhance/protect the value of a power-generating asset in bankruptcy from the perspective of the holder of a long-term energy contract.
- Commercial assistance to support hedge efficiency standards under the Federal.
- Overall financial and creditworthiness analysis of firms to determine financial capability to undertake design-build infrastructure projects.

Environmental Security

- Subject Matter Expert supporting the U.S. Southern Command ("USSOUTHCOM") Science, Technology and Experimentation Directorate ("J7") to capitulate and transition services for implementation. The end result is a database with relevant documents, a final report describing how the DoD can positively affect environmental security;
- Project Manager to Create the Energy Assurance Plan for the Virginia Department of Mines, Minerals and Energy. This includes conducting an inventory and providing a

vulnerability and risk assessment of energy infrastructure and distribution systems; revising the energy assurance plan; and conducting exercises that will educate public and private officials and test their knowledge of the revised energy assurance plan; and

- Subject Matter Expert on Risk and Vulnerability Assessment for Massachusetts, New York, Oregon, Missouri, Salt Lake City and Columbia MO.

<u>Renewable Resources</u>

- Designed and implemented the procurement of 38 million gallons of ultra-low sulfur diesel in the New York area. The process incorporated a staged approach to low-sulfur compliance and the mandate for a dedicated fleet transporting the fuel;
- Evaluated the pricing and procurement of white-tags in the context of environmental compliance;
- Designed and currently implementing a consulting approach to services associated with managing a CO_2 account. The approach incorporates a quantitative rigor similar to traditional financial metrics;
- Assisted a large Spanish company looking to purchase between 500 and 1,000 MWs of renewable energy in the U.S. over the next five years; and
- Recently developed an approach to estimate the extrinsic value of a compressed-air energy storage facility either as a stand-alone unit or as it integrates with other resources.

<u>County, State and Federal Government/Military</u>

- Subject matter expert in how the confluence of energy, food, water, health and climate change affect security.
- Hosted and led a team to evaluate the investment of an aluminum smelter and associated power generation in Bolivia to take advantage of the natural gas reserved in the area. The project included the preliminary feasibility for the aluminum smelter, setting up a series of visits to Bolivia, and a final assessment of the investment to include factors such as infrastructure, political stability, investment climate and poverty impact.
- Project Manager to Create the Energy Assurance Plan for the Virginia Department of Mines, Minerals and Energy. This includes conducting an inventory and providing a

vulnerability and risk assessment of energy infrastructure and distribution systems; revising the energy assurance plan; and conducting exercises that will educate public and private officials and test their knowledge of the revised energy assurance plan.

- Subject Matter Expert on Risk and Vulnerability Assessment for Massachusetts, New York, Oregon, Missouri, Salt Lake City and Columbia MO.

Professional History

- **Concentric Energy Advisors, Inc. (2012 – Present)**
- Assistant Vice President

- **R.W. Beck (an SAIC Company) (2007 – 2011)**
- Senior Director, Risk Management

- **Science Applications International Corporation (2006 – 2007)**
- Director, Risk Management

- **Pace Global Energy Risk Management, LLC (1998 – 2005)**
- Executive Director, Risk Management

- **Center for Strategic Studies, ITESM (1991 – 1995, 1997 – 1998)**
- Consultant/Researcher

- **Department of Economics, ITESM (1992 – 1998)**
- Associated Professor

- **Equifax de Mexico, S.I.C.S.A (1996 – 1997)**
- Financial Manager

Education

- Leadership Acceleration Program,University of Notre Dame, July 2004
- MS, Economics, University of Texas, 1995
- MBA, Finance, ITESM (Mexico), 1992
- BA, ITESM (Mexico), 1990
- Technician – Accounting,ITM (Mexico), 1986

Other

- Languages: English, Spanish (native speaker) and conversational German (mittelstuffe)
- Security: Top Secret security clearance granted in December 2011.

X. *APPENDIX B – SUMMARY OF PROGRAMS*

North American Case Studies in Hedging

1. New York Power Authority[34]

The New York Power Authority (NYPA) has a Governing Policy for Energy Risk Management ("Governing Policy"), which is approved by the Board of Trustees, and encompasses all management authorizations, directives, mandates, discretion and controls necessary to conduct NYPA's energy risk management program. Among the directives included in the Governing Policy is the formulation of an Executive Risk Management Committee ("ERMC"). The governance of hedging activities consist of the trustees establishing Policy, and management establishing directives via the Governing Policy with the guidance and oversight of the ERMC. Individual departments may draft supplemental procedures to direct and facilitate workflow, but must be consistent with the overall Governing Policy.

Functional duties are separated among the Front, Middle and Back Offices to provide checks and balances. It is important for duties to be segregated to reduce the risk of erroneous or inappropriate actions. The front middle and back offices should observe arms length behavior in the fulfillment of their duties. Standards of conduct are established in the Procedures and include compliance with market rules, and prohibitions against unauthorized trading, unreported trades, intentional misrepresentation or erroneously reporting terms of a deal, intentional inaccurate valuation of a position and unethical trading conduction. Material violations should be remediated to mitigate the risk impact and to address the risk of further violations must be presented by the appropriate operating manager to the Chief Risk Officer.

NYPA's primary Program objectives may be summarized as follows:

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[34] Public document found in http;//www.nypa.gov under the search term "New York Power Authority Governing Policy for Energy Risk Management".

- Match Core Business Objectives: Secure fixed or floating price structures or related options on energy-market commodities associated with generation or load-serving requirements. Fixed-price commitments shall not be executed for volumes in excess of high-confidence volume forecasts, including customer requirements and estimates of generating assets' supply and sales. The nature of derivative obligations shall be no more firm than the certainty of volumetric expectations, using options to secure financial rights without obligation where volumes are substantially uncertain.
- Mitigate Risk: Given volatile energy markets, manage energy and energy-related product costs and revenues toward the mitigation of unfavorable results and the promotion of results within acceptable boundaries.
- Improve Financial Performance: Where practical and in deference to objectives #1 and #2, reduce costs or increase revenues relative to defined targets and/or budgets by securing market positions or realigning existing hedge positions as deemed favorable.

These objectives may be expanded into two sets of operational objectives comprised of either commercial objectives to justify the Program or procedural objectives to facilitate the orderly implementation of the Program. With respect to the commercial objectives, the Program is aimed at promoting outcomes for NYPA and its customers that are within management defined tolerances by measuring and mitigating potential impacts of volatile energy market prices and volumetric uncertainty on forward costs and revenues.

The Procedures strive to guide and control all hedging related activities to facilitate the efficient attainment of commercial objectives. Hedging activities must be conducted in a non-speculative fashion. Hedging is only permitted to the extent that underlying volumes or exposures can be quantified with a degree of certainty appropriate to the hedge instrument to be used.

Strategies ratified by the ERMC contemplate the advance planning of hedge responses if and when risk metrics migrate to prescribed trigger levels. Also, strategies provide some discretion to the Front Office for limited hedge accumulation based on specific market conditions. A well articulated hedge strategy should be distilled down to explicit Decision Rules, which constitute a mandate and guidelines for the Front Office and compliance elements to be monitored by the Middle Office. Every hedge must be linked to an ERMC-ratified Decision Rule. The Decision Rules are subdivided into four categories:

- Preemptive – early volatility reduction

- Defensive – mitigation of cost of service or net income risk in response to prescribed triggers
- Value-Driven – hedges based on specified market conditions relative to defined financial targets and/or budgets
- Contingent – transactions aimed at mitigating potential of out-of-the-money hedge settlements, collateral, or counterparty exposures

NYPA's Program also provides for management of contract exposure, counterparty credit, management of collateral positions, and must operate within specified transaction limits for tenor and volume that vary by commodity. Generally, those limits provide for hedging 48 months out for natural gas contracts, with a maximum monthly hedge limit of 15 million Dth.

The key performance metrics that are monitored and reported for actual and potential outcomes include: Net income, Customer Revenue Requirement, Out of money hedge settlements, NYPA's collateral posting requirements, Unsecured counterparty credit exposure.

NYPA employs the following approaches to quantifying, assessing and monitoring risk:

- Price curves – Sourced from highly reliable independent providers of market-based quotes. Middle office is responsible for validating the accuracy of price data to assure that assessments are not materially degraded due to inaccurate price assumptions or the volatility implicit in those assumptions.
- Price volatilities and correlations - are calculated statistically using parametric distributions appropriate to each commodity. The validity of the distribution is tested by the mid office. For purposes of estimating VaR, marginal price volatilities shall be calculated from observed price changes over a 44-day rolling history for each commodity and each forward contract. Correlations among commodities shall also be quantified from that 44-day rolling history.
- VaR – the potential value migration that could result in less attractive hedge opportunities at the end of a holding period. These changes may be driven by marginal price volatility and in some case potential changes in volumetric expectations. It is measured typically at the 97.5% confidence level.
- Risk to Expiry – the potential value migration through the terminal date of any period, typically a calendar year using average volatilities over the time horizon to expiration of each forward contract. Assumes volatility will grow as tenor decreases, consistent with the seasonally-adjusted volatilities observed for comparable horizons.
- Out of Money Hedge Settlement Exposure – This is calculated by beginning with the current mark to market and then adding risk assessments calculated on a VaR basis as well as Risk-to-Expiry. When reporting out-of-the-money hedge settlement exposure to expiry, the

report should include the peak exposure (collar value) as well as the time frame for the expected peak exposure.

- Collateral Posting Exposure – Calculated at the ERMC-specified confidence level by quantifying the out-of-the-money hedge exposure related to each counterparty, subtracting the respective credit thresholds, and then summing the net collateral requirements that result. May also measure "Potential Future Exposure" by measuring the peak exposure after accounting for price migrations to expiry and the attrition of hedge positions.
- Unsecured Counterparty Credit Exposure – this exposure increases as hedges become more favorable to NYPA; it relates to market movements that are directionally opposite those contributing to out-of-the-money hedge settlement exposure. Some counterparties have established credit thresholds; in some cases no threshold is specified and maximum credit allowance must be constrained by limiting hedge positions. This may be calculated on a VaR basis as well as Risk-to-Expiry.
- Back Testing – performed to assure the sustained validity of risk metrics.

The CRO is responsible for a Compliance Template that reflects all material requirements of the hedging practices. The middle office should conduct a weekly review of each compliance element and report any material breaches to the CFO. At each ERMC meeting, the CRO reports the most recent weekly review and any issues that may have arisen. The Compliance Template shall include: transaction limits, hedge decision rules associated with ERMC-ratified strategies, risk metrics vs. specified tolerances, credit procedures and limitations, deal capture and confirmation procedures, pending counterparty issues with respect to collateral or confirmations.

2. Santee Cooper[35]

Santee Cooper is a state-owned electric utility in the Southeast that is routinely exposed to the price risk of natural gas that it procures to generate electricity. It distributes electricity to 163,000 retail distribution customers and provides power to more than 2 million customers.

Santee Cooper's risk management program is governed by its Board of Directors, an Executive Fuels Committee, a Risk Management Committee and the Controller's Office. The Objectives

[35] Derived from public documents found at http://www.santeecooper.com by typing "risk management" in the search form.

of the Program are to identify exposures to movements in natural gas prices; quantify the impact of those exposures on the Company's financial position; mitigate the impact of those exposures in line with the Company's identified level of risk tolerance; and monitor and report on the effectiveness those strategies have in managing risk. Specifically the objectives are stated as follows:

1. Match Core Business Objectives: Secure fixed or floating price structures for natural gas inputs that are best suited to the Company's core business objective. Under no circumstances shall natural gas transactions be executed which are not related to Company's core business objective.

2. Mitigate Risk: Given volatile natural gas markets, manage costs toward the mitigation of potentially unfavorable results and the promotion of results that fall within acceptable, favorable boundaries

3. Improve Cost Effectiveness: Where practical and with deference to objectives #1 and #2, reduce the cost of natural gas purchases.

The permissible hedging instruments are restricted to specific products, instruments and amounts specified. Risk managed transactions may be executed for terms up to 24 months in the normal course of business or for greater terms with the approval of the EFC. Risk management transactions may include the following: i) hedging the cost of natural gas purchased for core business objectives; ii) unwinding of hedges to accommodate changes in expected natural gas requirements; and iii) unwinding of hedges for economic reasons, subject to explicit constraints set by the EFC.

Defensive hedges are placed to protect the upper price boundaries and are established below. These represent minimum hedge quantities. The total hedge percentage is determined as follows: (Fixed price volumes (futures/swaps/fixed price physical) + Delta Equivalent volume from options)/(total expected consumption).

Programmatic hedges are accumulated in fixed percentage increments independent of any other requirements to defend explicit boundaries and independent of a market view. The current programmatic hedge percentage is 5% of each month's requirements. Execution of programmatic hedges begins 24 months before the expiration of the contract and ends 19 months before the expiration of the contract, resulting in a maximum cumulative programmatic hedge amount of 30%.

Discretionary hedges are those placed to take advantage of market opportunities characterized by the sentiment and the momentum of the market. Execution of discretionary hedges takes place between 1 and 18 mos. before the expiration of the contract.

Specific protocols have been established to monetize value. First, for all types of hedges, any time the value of the hedge exceeds 10% of the total market value (or hedge yield), contingent on not violating defensive protocols, the incremental hedge may be executed in the above increments. Or, as indicated above, any time the sentiment of the market exceeds 0.5 standard deviations, monetize the first 15 percentage points of all discretionary hedges; or any time the sentiment of the market exceeds 1.0 standard deviation and a change in the momentum from positive to negative of the market occurs, monetize the value of the remaining discretionary hedges. The two conditions will be tested jointly and the trigger of the lift recommendation will be exercised as soon as on e of the conditions is met.

The forward portfolio price is quantified daily by the Manager of Energy Risk Control and adjusted when necessary to reflect changes in the Company's expected purchases or the execution of transactions.

The maintenance of risk management records and the quantification of financial implications are trade secrets called, in aggregate, the Risk Management Book ("Book").

3. New Jersey Natural Gas[36]

[36] Derived from publicly-available documents found at http://www.njng.com by typing "financial risk management program" in the search box.

New Jersey Natural Gas ("NJNG") is a New Jersey Gas LDC, whose hedging program was studied over the period 2001-2009 by Pace Consulting / Vantage Consulting at the request of the NJ Public Utilities Board. NJNG's hedging practices are governed by the Guidelines and Procedures established by its Risk Management Committee. NJNG is authorized to utilize futures contracts, commodity swaps and basis swaps for its hedging program. NJNG's hedging activities are divided into two distinct components: 1) basic hedging and 2) storage optimization. The objectives of its hedging plan are stated to be: Achieve a certain hedge level prior to the onset of each winter season, and realize storage costs below its benchmark.

NJNG hedges to achieve a minimum hedge ratio of 75% for the November – March winter period by November 1, and it also hedges at least 25% for the ensuing 12-month April-March period, with the purpose of ensuring that no more than 25% of normalized winter gas load is exposed to market prices. Storage volumes apply to the winter requirements, with storage making up approximately 50% of NJNG's expected winter send-out. This practice is followed to satisfy the 1st objective to achieve a targeted hedge level before the onset of winter.

For its second objective to realize storage costs that are below the benchmark, NJNG uses financial instruments to capture arbitrage value. NJNG executes its storage incentive strategy largely through the use of options. Any costs savings are shared with the customers. NJNG trades in and out of positions regularly in an effort to extract arbitrage value from price movements.

Performance of the program is monitored by reviewing the WACOG of NJNG's gas portfolio versus the market price. This measure was thought to provide a broad indication of the program's overall cost efficiency and its responsiveness to specific market conditions. None of these hedges were performed in accordance with a value or budget decision rule. New Jersey's commodity prices are highly correlated with the Henry Hub settlement prices.

4. Puget Sound Energy

Puget Sound Energy's risk management function oversight is provided by the Energy Risk Control Department. This department is led by the Vice President of Finance and the Treasurer. PSE's Energy Management Committee ("EMC") – composed of senior PSE officers – oversees the activities performed by the EPM Department. The EMC is responsible for providing oversight and direction on all portfolio risk issues in addition to approving long-term resource contracts and acquisitions. The EMC provides policy-level and strategic direction on a regular basis, reviews position reports, sets risk exposure limits, reviews proposed risk management strategies, and approves policy, procedures, and strategies for implementation by PSE staff. In addition, PSE's Board of Directors provides executive oversight of these areas through the Audit Committees.[37]

The Objectives of PSE's hedging program is to reduce risk and rate volatility, specifically to insulate customers from volatile wholesale commodity markets and provide stable rates and to reduce PSE's earnings volatility by removing power portfolio risk. The Gas portfolio is hedged in a programmatic manner, with some discretion as to timing. Minimum hedge targets must be met regardless of price and hedging may be accelerated/decelerated based on the market view.

The structure of the Core Gas portfolio hedging strategy can best be described as programmatic, with some discretion. It is a two-dimensional matrix, where both the time until delivery and required hedged volumes establish thresholds for executing wholesale gas market transactions. However, there is an additional price component to this matrix that accelerates hedging if prices fall to a certain level, referred to as the Threshold Price Level. The Threshold Price Level is derived by examining fundamental industry factors and modeling. Essentially, this price represents a "floor" where PSE feels comfortable accelerating its hedging based on current market prices, estimated supply costs, and the current Purchased Gas Adjustment mechanism. In low-price environments a third component is activated, referred to as the Cash Cost component. This component raises the hedge level beyond the target established by the programmatic components and allows incremental hedging when prices approach triggers, established through a quarterly analysis of natural gas producer's variable operating costs.

[37] Exhibit No. (DEM-3C), Docket UE-11-1048, 2011 PSE General Rate Case, Witness: David E. Mills, WUTC v. Puget Sound Energy, Inc., Second Exhibit (Confidential) to the prefiled Direct Testimony of David E. Mills on behalf of Puget Sound Energy, Inc. – Redacted Version - (June 13, 2011)

PSE found that in a benchmarking and market research initiative that customers prefer a longer period of rate stability and that industry leading companies were engaged in longer term hedging practices than PSE. Given this and other information, PSE determined it could be beneficial to expand their hedging horizons. The line of credit requested and approved in the 2006 General Rate Case provides PSE increased flexibility to monitor and more actively address the exposures associated with its power and core gas portfolio positions, as well as its natural gas for power position.

In May 2004, PSE began to employ a metric called Margin at Risk, which measures risk reduction as a result of incremental hedging. PSE has incorporated the Margin at Risk concept into the evaluation process for hedge strategies to measure risk reduction for various alternatives. A series of hedge strategies, or transaction types, are run through the portfolio, providing a table of how much risk reduction is gained, by month and by strategy. The Margin at Risk concept assists with deciding how to allocate dollars in a credit-constrained environment, thus providing an additional tool for choosing between available commodities.

PSE's Core Gas risk system models the estimated potential variability of future prices using 250 price scenarios. This risk system permits PSE to model scenarios of prices and storage activity versus load requirements to represent future projected Core Gas portfolio needs. For example, the 250 price scenarios the risk system models help incorporate monthly storage variability to calculate a conservative volume available to hedge under the Cash Cost methodology described above. In addition, PSE employs a metric called Margin at Risk, to inform decisions of which natural gas basin is most attractive to hedge.

As described above, the programmatic Hedging Plan is set up to systematically reduce the total net exposure, within maximum and minimum limits set forth in the plan outlining the amount of hedging that can or must be done each month, so that the total net exposure for each month will fall within the limits of the Procedures Manual. Every month, the risk system calculates the total net exposure to be reduced for the Programmatically Managed Hedge period.

The net exposure drives transactions only to the point of showing whether PSE's exposure is within the maximum and minimum monthly limits of the plan. EPM Department staff must then make use of market fundamentals, water supply and weather forecasts that impact the wholesale electric and gas markets to decide whether to press toward the maximum or minimum monthly limits, or somewhere in between. EPM Department staff also determines when and how to execute such transactions to maintain each month's net exposure within the maximum and minimum limits.

5. Cascade Natural Gas Company

Cascade is a subsidiary of MDU Resources, serving more than 260,000 customer in 96 communities, of which 68 are in Washington state and 28 in Oregon. Cascade's serves approximately 197,000 customers in the state of Washington. The Company had gas sales of 30.5 million Dth and receives gas on two interstate pipelines, Gas Transmission Northwest (GTN) and Northwest Pipeline. Cascade uses 1.2 million Dth of gas storage capacity and has 562,200 Dth of LNG from Northwest pipeline to supplement its gas supply during peak demand periods. The Company obtains natural gas supplies from three primary supply sources: the AECO Hub, the Sumas Hub, and the Rockies area basin. For spot market purchases it uses mainly monthly price indices tied to the delivery hubs and gas basins in which it purchases natural gas. Cascade has a Purchased Gas Adjustment (PGA) mechanism in retail natural gas rates to recover variations in natural gas supply and transportation costs. The Company has annual PGA filings.

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." 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.

The primary objective of the hedging strategy is to reduce volatility. The company has recently hedged 34% of gas supply. Cascade's hedging strategy involves locking in prices for up to three years before the gas is needed. Financial derivative transactions are allowed to span up to 42 months.

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. 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.

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 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.

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. 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. 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 consists 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.

The Company reports its natural gas procurement activities through its PGA process, however it is not required to convey its hedging strategies for the upcoming months or its assumptions. It makes a PGA filing within a maximum of 15 months since the effective date of the last PGA or file supporting documents demonstrating why a rate change is not necessary. The Company accrues the difference between the actual gas costs and the amount billed to customers in a deferred account and files a monthly report showing the activity in the deferred account.

I. *APPENDIX C – AGA RATE INQUIRY*

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LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2011-12 WINTER HEATING SEASON

I. Introduction

Each year local natural gas utilities develop a plan to reliably help meet customer needs during winter heating season peak consumption periods. The plan is usually based on a forecast of expected loads and is later adjusted to actual weather-induced demand requirements. Numerous scenarios are examined when building a seasonal natural gas supply portfolio—always against the backdrop of "normal," which is defined by companies based on local weather information and system requirements from years past. Supply tools, such as firm pipeline capacity, access to on-system or pipeline storage, peak-shaving capabilities, local production and even third-party transportation arrangements, are carefully considered. In many cases, these plans are submitted to state regulators for approval prior to the start of the winter heating season.

As local gas utilities and natural gas consumers approached the 2011-12 winter heating season, market acquisition prices at Henry Hub had been falling for two months (since September 2011). With a winter that turned out to be a non-event nationwide, natural gas prices continued to fall through April 2012 (actually below $2.00 per MMBtu on average in April) never reaching the level demonstrated during the preceding summer in 2011 (above $4.00 per MMBtu). The combination of a mild winter and extraordinarily low acquisition prices made for savings in the pocketbooks of many natural gas consumers. In fact, not until July 2012 did Henry Hub spot and NYMEX prompt-month pricing both gaze above $3.00 per MMBtu – a remarkable run of low gas costs for all domestic consumers. Even with lower wellhead prices, domestic natural gas production was sustained at about 64 Bcf per day, and with no real challenge for seasonal demand during the winter, continued to exert downward pressure on natural gas acquisition prices.

Underground storage working gas volumes began the winter heating season, just prior to the change from weekly net injections to weekly net withdrawals, above 3.8 Tcf ended on March 31, 2012 at nearly 2.5 Tcf – an unprecedented volume of working gas at season's end. The six-month period October 2011 through March 2012 turned out to be about 17.5 percent warmer than normal for the nation as a whole. The coldest month during the 2011-12 winter heating season was in January, based on the total heating degree day statistics from the *National Oceanographic and Atmospheric Administration*. However, on a weekly basis, only one week of the 22 weeks from November 5, 2011 through March 31, 2012 was colder than normal nationwide.

With this backdrop, this analysis describes critical elements of the 2011-12 winter heating season (WHS) and summarizes data acquired from AGA member local distribution companies (LDCs) via the AGA *Winter Heating Season Performance Survey*. For this year's survey, questions focused on peak-day and peak-month supply practices, pricing mechanisms, as well as regulatory and market hedging practices.

This year responses (whole or subsets) were received from 63 local gas utilities with service territories in 37 states. The sample companies had an aggregate peak-day sendout of 46.2 million Dekatherm (Dth), acknowledging that the peak-day did not occur on the same calendar day for each company. However, these same companies *planned* for a peak-day of 66.8 million Dth in aggregate, which means that only about 69 percent of the planned peak sendout volume was actually required during the 2011-12 WHS. This makes this the ninth year consecutively that aggregate actual peak-day sendout fell short of aggregate design peak-day volumes for respondent companies.

The purpose of this report is to document gas delivery system operations of the surveyed local gas utilities during the past winter heating season and to help provide insights into gas supply trends and procurement portfolio management. ***The aggregated data presented in this report are not to be interpreted as standards or best practices for gas supply management.*** Instead they represent a snapshot of aggregated supply procurement practices of those companies that participated in this year's survey. In some cases, the report compares survey results for the 2011-12 winter heating season with those reported in prior years. It should be noted, however, that the compared samples are not identical and the supporting data are not audited or normalized for sample differences, weather or other factors.

II. Executive Summary

This report is based on survey responses submitted by 63 AGA member local gas utilities, representing 46 corporate entities. These companies had a cumulative, non-coincident, peak-day sendout of 46.2 million Dth and an average peak-day sendout of 732,970 Dth. Whereas the coldest day, as reported by respondents, fell fairly evenly in the months of December, January and February during the previous winter heating season, for the 2011-12 WHS the peak temperature day predominantly occurred in January (53 of 63 respondents). Results of the winter heating season survey are generally presented as counts of companies that fit into percentage ranges (1-25%, 26-50%, and so forth) of supply volumes. The intent of this report is to document the data as a snapshot of supply behavior by large purchasers of natural gas—in this case the surveyed local distribution companies (LDCs).

Natural Gas Market

- The U.S. natural gas market balances supply and demand at something greater than 66 Bcf per day "on average." However, requirements for natural gas by consumers—and particularly during the winter heating season—are not average.
- During the period of November 1, 2011 through March 31, 2012, total consumption of natural gas in the U.S. ranged from about 60 Bcf per day on a warm March day to about 105 Bcf (including net exports to Mexico) on the coldest winter day in February, according to *Bentek Energy LLC* – a huge swing in daily winter heating season demand.
- In fact, the residential and commercial sectors of the market were most responsible for the dramatic swings in customer requirements, rising to about 53 Bcf per day on a cold February day in 2012, to winter heating season low of 16 Bcf per day on March 21 and 22.

2

Weather

- For the two months (September-October) just prior to 2011-12 winter heating season, conditions were 26.6 and 7.3 percent colder than last year, but warmer than normal by 6.9 and 9.4 percent respectively. This pattern continued through the winter with November 2011 through March 2012 recording warmer than normal temperatures for the nation as a whole. In March, conditions were 36.8 warmer than normal on a national average basis and, in fact, the National Oceanographic Atmospheric Administration has reported that the first six months of 2012 (including the winter heating season months of January through March) were the warmest ever recorded for a January through June period in the lower-48 states.

- The *peak* consumption day occurred in January for 53 of the 63 survey companies, while six identified February and four pointed to December as the month in which their peak day load occurred. Simply stated temperatures around the country were consistently warmer than normal throughout the winter heating season months.

- For the period of October 1, 2011 through March 31, 2012, cumulative heating degree days were 18.4 percent fewer than the previous year and 17.5 percent fewer than normal (meaning warmer than normal) on a national basis. On a regional basis, conditions were consistently warmer than normal, ranging from 0.8 warmer in the Pacific to 22.4 warmer in the East North Central region.

- This winter differed from 2010-11, which started out warmer than normal, reversed to colder than normal conditions in the core winter months of December-February, and then reverted back to once again warmer conditions in March. For an example of cumulative weather resulting in a consistently colder-than-normal winter, one must look as far back as 2000-01. Winter weather has been decidedly warmer than normal on average compared to the 30-year norm since that remarkable winter, when sustained cold temperatures and concerns regarding a tight supply market resulted in significant natural gas price leaps.

Gas Supply Portfolios

Local gas utilities build and manage a portfolio of supply, storage and transportation services, which include a diverse set of contractual and pricing arrangements to meet anticipated peak-day and peak-month gas requirements. For the 2011-12 winter heating season, companies responding to the AGA survey planned for 66.8 million Dth of peak-day gas sendout, but only 69 percent (46.2 million Dth) of the volume was actually required because of the lower than projected peak consumption levels nationwide. As a point of reference, last year's sample of 51 companies planned to deliver about 60.8 million Dth of peak-day gas requirements but in fact delivered only about 47.3 million Dth (about 78 percent). In addition, thirty-one of the 63 companies in this year's survey indicated that their design day forecast includes a margin for error, and twenty-seven of those companies noted that the forecast error margin had been approved by the appropriate state oversight agency.

Local gas utilities apply a standard or develop a methodology for determining a design peak day temperature calculation and, of course, that influences the construct of their gas supply portfolio. For the 2011-12 WHS survey, eighteen companies noted using a 1-in-30 year risk or probability of occurrence, while 26 companies choose other time periods, including up to 1-in-100 year considerations. Nineteen companies used other methodologies including a historical peak, a stochastic cost-benefit analysis, Monte Carlo statistical simulation, and coldest effective degree day in a 30-year period.

- It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak day and peak month. Fifty-four of 63 companies indicated that firm supplies were a part of their gas supply portfolio, including thirty-three companies that used firm supplies to meet between 26 and 75 percent of their peak-day volume requirements.

- Forty-two companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage; 46 companies noted that up to 50 percent of the deliveries arriving at their city gate on a peak day were earmarked for transportation customers on their system; and 19 companies flagged on-system storage as the source of up to 50 percent of peak-day supplies.

- Long-term agreements, defined as one year or longer, were used by 36 of 63 reporting companies within their peak-day gas supply portfolio (compared to 29 of 49 companies the previous year), but only 11 companies used long-term contracts for more than 50 percent of purchased gas on a peak day (compared to 6 companies the previous year). Mid-term (more than one month, less than one year) agreements were the most utilized for 2011-12 peak-day purchases, with 52 of 61 companies having such contract terms. In fact, 28 companies indicated that more than 50 percent of their peak-day natural gas supplies were acquired via mid-term agreements.

- When asked to describe the distribution of gas supply purchases among suppliers, respondents cited independent marketers, producers and producing company affiliates more than any other class of supply aggregators.

- When asked if the company used asset management agreements for any portion of its gas supply purchases during the 2011-12 winter, 22 companies answered yes, while 29 answered no.

Supply Pricing Mechanisms and Hedging Issues

Many factors play a role in the market pricing of natural gas and of transportation services, including weather, storage levels, end-use demand, financial markets and various operational issues. When asked to identify the tools most effective to managing supply and price risk, survey respondents largely cited physical storage, and also mentioned fixed pricing (including advanced purchases at fixed prices), index pricing (both first of month and daily), and call and swing options.

- For long-term supplies (one year or more), 31 of the 37 companies that had such supplies used first-of-month (FOM) pricing for a portion of their supplies, including 20 companies that used FOM for at least 50 percent of long-term gas purchases. Thirteen companies utilized daily pricing, and 12 made use of fixed pricing.

- Mid-term purchases (more than one month, less than one year) were reported by 42 of 53 companies as most often tied to FOM indices for significant volumes of gas. In addition, daily mechanisms (27 companies) and fixed-prices (21 companies) were included in the mid-term pricing basket.

- Eighty-one percent of companies responding to the AGA survey (51 of 63 companies) indicated that they used financial instruments to hedge at least a portion of their supply purchases for the 2011-12 winter heating season. This differs from one year prior where 92 percent (of a different sample of companies) indicated using financial hedging tools. In contrast, during the 2004-05 winter only 70 percent of survey companies used financial tools, while only 55 percent did so three years prior (during the 2001-02 winter).

- Fixed-price contracts and options were equally cited (by 26 companies respectively) as most often used to hedge a portion of gas volumes delivered on a peak day. Other regularly used financial tools include swaps (22 companies) and futures (14 companies). The use of financial tools may be understated in this report inasmuch as some volumes delivered to

LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

- Companies use a portfolio of timed hedges to balance their approach to strategic price planning. When asked about the strategic timing of their hedges, 43 of 51 companies (84 percent) indicated that they hedge 7-12 month forward for a portion of their supplies, while 42 of 51 companies employ a six-month-or-less timeframe. Twenty-seven companies use a 12-month-or- greater approach to hedge a portion of their supplies. Of these 51 companies, 23 employ all three timing strategies.

- On the physical side in preparation for the 2011-12 WHS, 61 of 63 respondents reported using storage as a natural hedging tool. Thirty-three of those companies hedged between 25 and 51 percent of winter heating season supplies using underground storage, compared to 27 companies last year. Another 20 companies employed this physical hedge for 1 to 25 percent of their supply portfolio.

- Only four out of 63 survey respondents indicated that they used weather derivatives during the 2011-12 winter heating season. This compares to two of 51 companies in the prior WHS.

- When asked about their own regulatory environment, all 50 companies that answered the question with an answer other than "not applicable" indicated that financial losses and gains tied to hedging were treated equally by the regulator.

- When asked about the focus of their regulator regarding gas purchases, 35 of the 56 respondents that knew the answer indicated that their regulator was interested equally in the lowest price possible and stable prices. Twelve said that a lowest price was the only focus, while nine tagged stable prices as the concern.

- Thirty-four of the 51 companies that hedge a portion of their gas supply purchases noted that they plan to hedge at the same level during the upcoming winter heating season (2012-13) as they did in the past winter. Eleven companies plans to hedge less, while five companies are undecided. Of the twelve companies that do not currently hedge their gas purchases, one company intends to utilize hedging tools for the 2012-13 WHS.

Gas Storage

Production and market area storage are key tools for efficiently managing LDC gas supply and transportation portfolios. However, it should be noted that storage practices are no longer dictated only by local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing and other commercial arbitrage opportunities that take place at market hubs and city gates.

- Sixty of the 61 companies indicated that weather-induced demand, among other factors, compelled them to utilize storage services. Respondents also cited no-notice requirements (51 companies), "must turn" contract provisions (38 companies), pipeline operational flow orders (24 companies) and arbitrage opportunities (22 companies) as reasons to maintain storage services within their gas supply portfolio during the 2011-12 winter heating season.

- Must turn provisions may be in place for some storage contracts as a way of maintaining facility integrity through an optimal pattern of injection and withdrawal into and from a storage field. With that said, at the end of 2011-12 winter heating season, storage inventories finished much higher (nearly 2.5 Tcf of working gas remaining) than the prior five-year average and the prior year. Therefore, sixty-two percent of responding companies (38 of 61) said that must-turn provisions influenced their use of storage during the 2011-12 winter.

- Fifty-two of the 60 companies that answered the question used first-of-month index pricing to purchase gas for injection into storage, and 40 percent (or twenty-one) of those companies indicated that 76-100 percent of gas injected into storage was based on FOM prices. Forty companies indicated that they purchased a portion of their stored gas in the daily market, however, daily pricing tended to account for less than 50 percent of purchased storage volumes. Twenty-nine of 60 companies (just over 48 percent) used fixed-price schedules for some portion of their storage purchases, compared to 50 percent the prior year.

- Twelve of 63 companies indicated that they were either constructing or studying the potential for adding underground storage during the next five years, while nine were considering adding market-area LNG or propane peak-shaving capacity to their gas supply assets of which one was in the process of building peak-shaving facilities.

LDC Transportation and Capacity Issues

Transportation-only customers have assumed a high profile among all customers served by local gas utilities. Managing pipeline capacity efficiently is a challenge for many utilities and can involve the release of capacity to the secondary transportation market.

- From April 2011 to March 2012, 38 to 47 of the survey companies (varying with the month) released their unneeded pipeline capacity on a monthly basis to the secondary market. Twenty-five to thirty companies (depending on the month) released up to 25 percent of their pipeline capacity. During the spring-summer of 2011 (April through August), from seven to eight surveyed companies per month released 26 to 50 percent of their capacity.

- Only 18 of 63 companies reported that operational flow orders (OFO), issued by pipeline companies, had an impact on their service territory during the 2011-12 winter heating season. The median number of these OFOs was 5.5 and the median duration was two days. Only one company reported consequential storage "critical day" issuances by system operators.

III. Natural Gas Market Overview

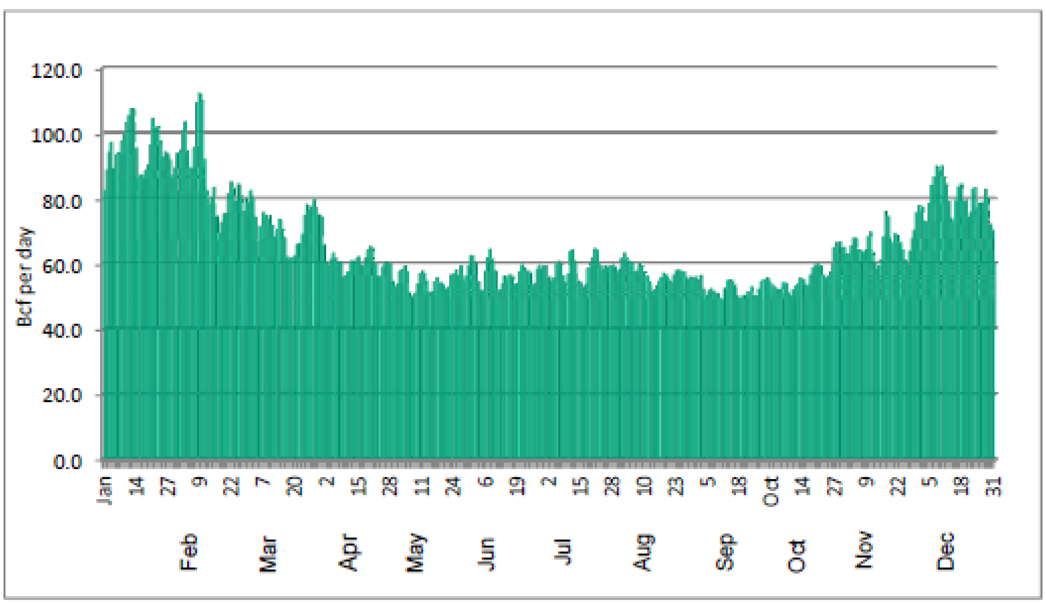
Why does a natural gas utility build a *portfolio* of natural gas supply tools to meet customer requirements during a given winter heating season? While the obvious reason is that companies want to deliver natural gas to customers reliably and at the lowest possible cost, another fundamental motivator is mitigating market uncertainty. Of course weather often introduces an element of the unknown for gas supply planners throughout the country.

As a national trade association, AGA usually describes national natural gas markets, based on annual or monthly data. Since 1995 and up to 2009, U.S. natural gas consumption had been about 22-23 Tcf annually, while U.S. natural gas production has been about 18-19 Tcf annually. In 2010, domestic natural gas consumption reached 24 Tcf and U.S. natural gas production reached 21.3 Tcf. In 2011 domestic natural gas production grew even more to 23 Tcf. Even though these data indicate a level of stability in the gas market, gas supply planners at local utilities face a very different picture – one that varies daily with fluctuating conditions that may turn extreme during winter heating season months.

It is a known fact that a balanced natural gas market corresponds to supply matching demand. Today's U.S. natural gas market balances consumption with domestic and international supplies at about 66 Bcf per day on average. However, on a daily basis during the course of a winter heating season natural gas consumption can fluctuate significantly. The graph in Figure 1 represents daily natural gas consumption from January through December 2011 and illustrates that winter heating season daily consumption does not necessarily correspond to annual or monthly averages. For example, from January 1 through March 31, 2011 daily natural gas consumption ranged from as little as 60 Bcf to over 100 Bcf. The graph also shows that consumption fell to well below 60 Bcf per day for much of May through September, leaving some gas in the 66 Bcf-per-day supply market as a source of underground storage replenishment.

FIGURE 1

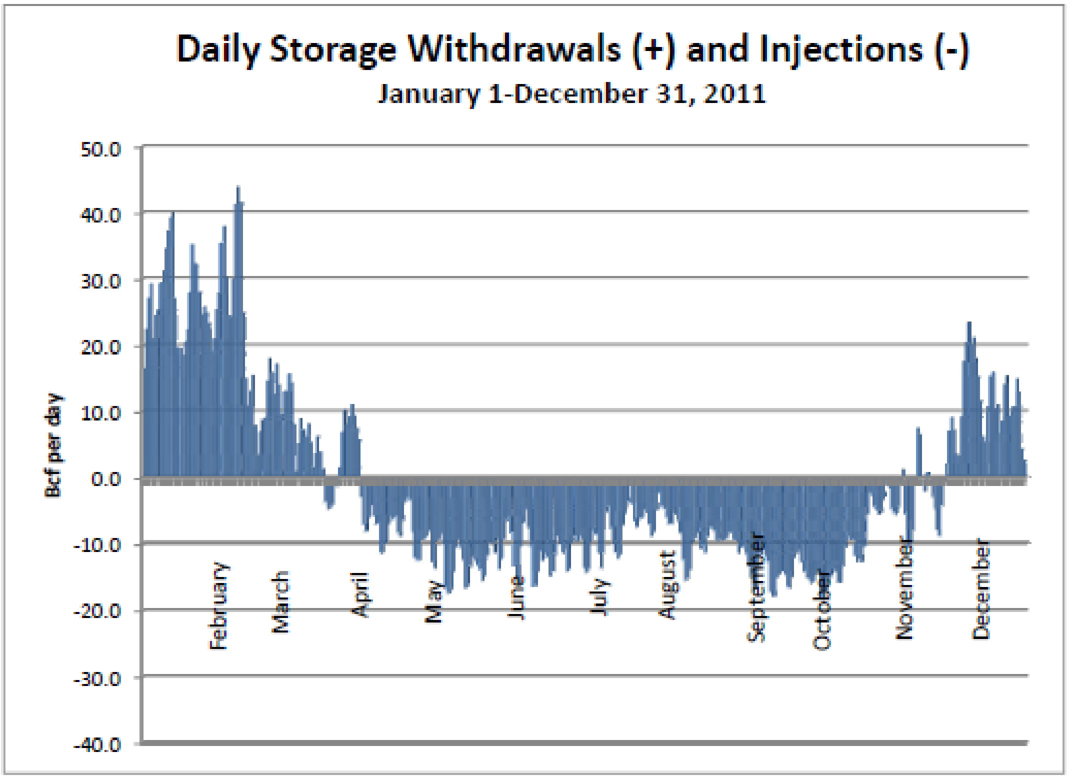
U.S. Daily Natural Gas Consumption 2011



Source: Bentek Energy, LLC, *Energy Market Fundamentals*, December 31, 2011

Figure 2 shows the net withdrawals from storage as a positive supply source and the net injections as a demand requirement (below the zero line). A look at only the residential and small commercial sectors provides an even starker example of daily demand fluctuations.

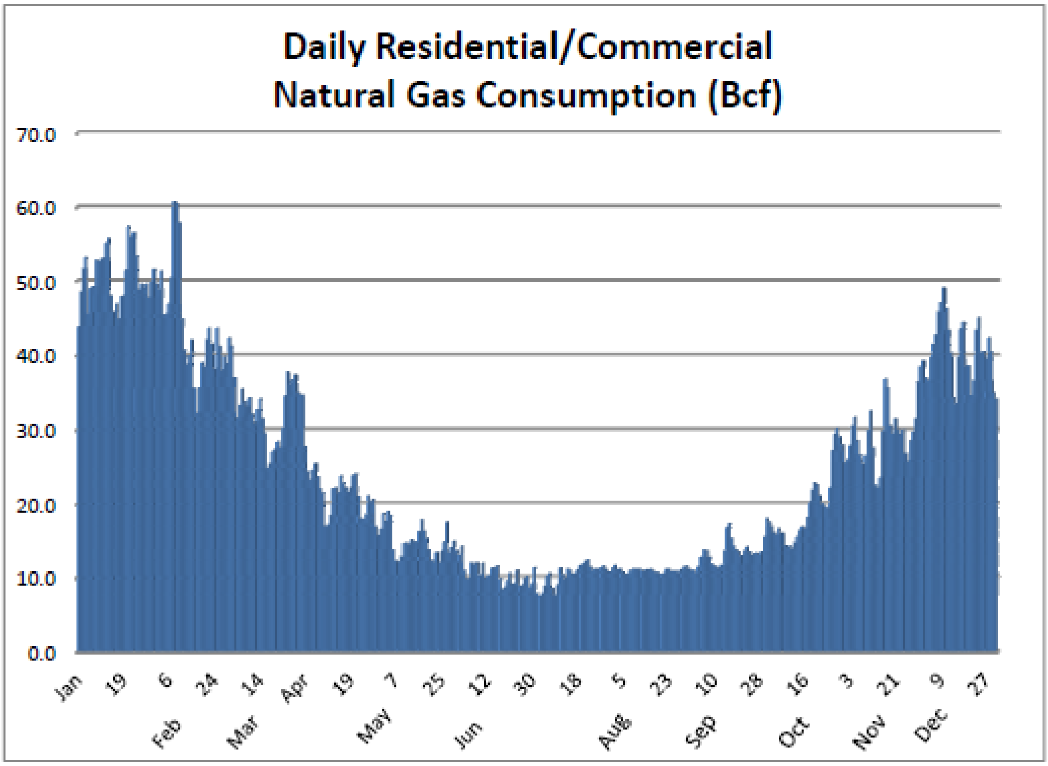
FIGURE 2



Source: Bentek Energy, LLC, *Energy Market Fundamentals*, December 31, 2011

Figure 3 (on the following page) graphs residential and commercial natural gas consumption data from January 1 through December 31, 2011. Here we see daily sector consumption as low as 16 Bcf for a warm winter day in March sharply contrasted with an over 50 Bcf consumption day in January and February. On a national basis, this represents more than a 100 percent load swing for natural gas utilities during the winter heating season. In most cases, changes in natural gas requirements are met with a package of supply tools including underground storage, peak-shaving facilities and others. For an individual utility this poses the ongoing challenge of meeting customer requirements each day of every winter and is the starting point for developing a portfolio of tools that are geared toward meeting this challenge.

FIGURE 3



Source: Bentek Energy, LLC, *Energy Market Fundamentals*, December 31, 2011

IV. Weather 2011-12 Winter Heating Season

According to data from the *National Oceanographic and Atmospheric Administration* (NOAA), the 2011-12 winter months were consistently warmer than normal on a national basis, resulting in an incredible 17.5 warmer than normal winter on a cumulative basis. This differs from the 2010-11 winter heating season, where the core months (December-January-February) were colder than normal, while November and March were slightly warmer. Both the 2008-09 and 2009-10 winter heating seasons were slightly warmer than normal based on heating degree day measures from October through March – 0.2 percent and 1.5 percent, respectively.

This winter heating season, heating degree day totals varied from 6.9 warmer in September to 36.8 warmer in March 2012. For the 22-week period of November 5, 2011 to March 31, 2012, only one week was colder than normal and two were at normal conditions compared to NOAA's 30-year norm. In fact, NOAA reported the six-month period to begin 2012 as the warmest January through June on record in the lower-48 states. On a regional basis, cumulative conditions over the winter months were warmer than normal in every area of the country. Deviations from temperature norms for the various regions of the country varied from 0.8 warmer (Pacific) to 22.4 warmer (East South Central).

TABLE 1 MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA OCTOBER 2010 – MARCH 2012				
MONTH	PERCENT CHANGE FROM NORMAL			
	2010-11		2011-12	
October	15.5%	Warmer	9.4%	Warmer
November	3.4%	Warmer	13.1%	Warmer
December	8.0%	Colder	12.3%	Warmer
January	3.9%	Colder	18.0%	Warmer
February	2.5%	Colder	12.7%	Warmer
March	0.3%	Warmer	36.8%	Warmer
TOTAL	1.2%	Colder	17.5%	Warmer

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

V. Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services to meet expected peak-day, peak-month and seasonal gas delivery requirements. In today's business environment, gas portfolio managers continually attempt to strike a balance between their need to minimize gas-acquisition risks and their obligation to provide reliable service at the lowest possible cost. Given the reality of significant deviations from normal weather patterns (warm and cold), volatility in commodity prices, and regulatory scrutiny of costs to consumers, local gas utility exposure to hindsight analysis regarding gas supply practices is ever present.

With that said, local gas utilities apply a standard or methodology for determining a design peak day temperature calculation and, this of course influences the construct of their gas supply portfolio. For the 2011-12 WHS survey, companies described their methodology for determining their design day calculation as follows: eighteen employed a 1-in-30 year risk of occurrence, four used a 1-in-15, three used a 1-in-20, two used a 1-in-5, and one used a 1-in-10 year occurrence probability. Sixteen companies utilized time period criteria, ranging from two years to 1-in-100 years. Nineteen companies indicated their use of other methodologies, such as historical peak adjusted for current and known changes, Monte Carlo statistical simulations, and weighted averages over specific time frames. In addition, thirty-one of the 63 companies in this year's survey indicated that their design day forecast includes a margin for error, and twenty-seven of those companies noted that the forecast error margin had been approved by the appropriate state oversight agency.

The peak temperature day predominantly occurred in January for survey respondents (53 of 63 companies). For these 63 companies, the aggregate peak-day sendout was 46.2 million Dekatherms during the 2011-12 WHS, making up 69 percent of the 66.8 million Dekatherms projected for peak-day requirements. The majority of respondents (46 of 63 companies) delivered between 60 and 80 percent of projected peak-day requirements.

Respondents were asked to depict their peak day and peak month delivered gas volumes by supply source. Table 2 and Figure 4 illustrate the diversity of gas supply sources available to LDCs. However, it is not surprising that purchases moved by firm transportation provided much of the gas to consumers for the peak day and peak month during the 2011-12 WHS. Fifty-four of 63 companies indicated that firm pipeline supplies formed a part of their gas supply portfolio, including twenty-four companies that showed 26 to 50 percent of their required peak-day volumes coming from firm supplies. Another twelve companies indicated that more than 50 percent of their peak-day supplies were moved via firm pipeline transportation.

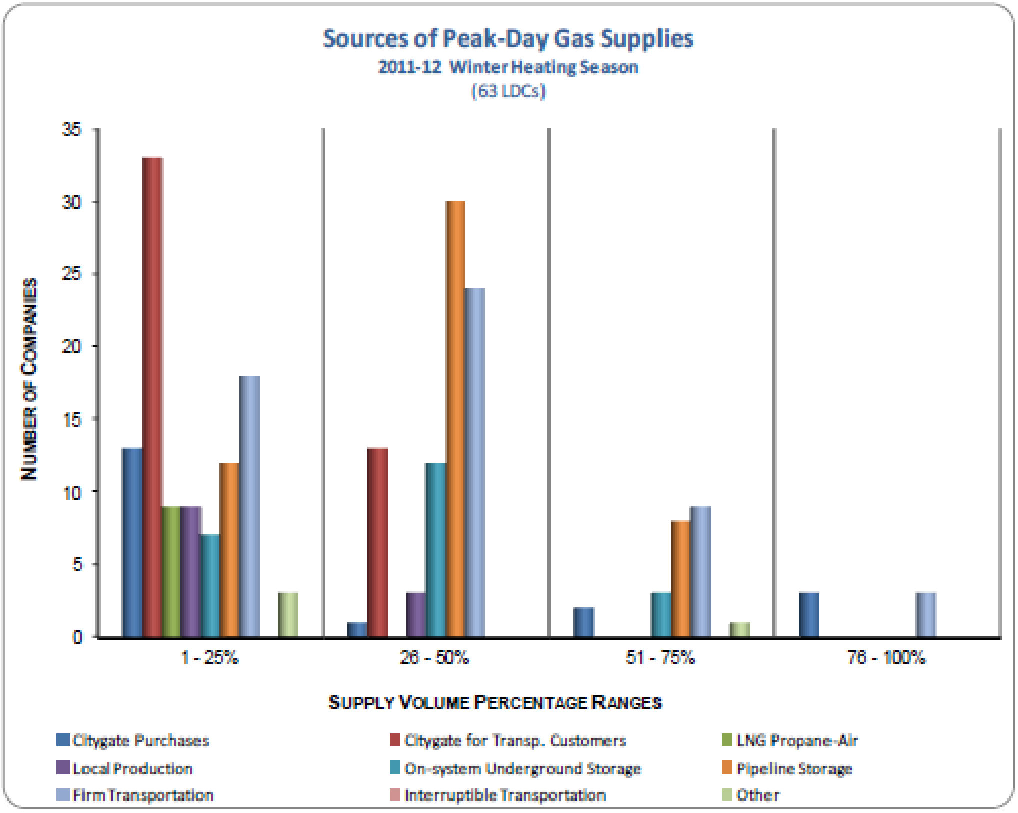
As shown in Table 2, peak-month supplies were heavily weighted toward purchases via firm transportation. As with peak-day supplies, peak-month supplies tended to be supplemented with city gate deliveries for transportation customers, pipeline or other storage, city gate purchases, on-system storage, local production, and some LNG or propane air.

TABLE 2
SOURCES OF LDC PEAK GAS SUPPLIES
2011-12 WINTER HEATING SEASON
(63 Companies)

SUPPLY VOLUME PERCENTAGE RANGES	CITY GATE PURCHASES	CITY GATE SUPPLIES FOR TRANSPORTATION	LNG PROPANE AIR	LOCAL PRODUCTION	ON-SYSTEM UNDERGROUND STORAGE	PIPELINE OR OTHER STORAGE	PURCHASES MOVED VIA FIRM PIPELINE TRANSPORTATION	PURCHASES MOVED VIA INTERRUPTIBLE TRANSPORTATION	OTHER
PEAK DAY									
1 – 25%	13	33	9	9	7	12	18	0	3
26 – 50	1	13	0	3	12	30	24	0	0
51 – 75	2	0	0	0	3	8	9	0	1
76 – 100	3	0	0	0	0	0	3	0	0
0	44	17	54	51	41	13	9	0	59
PEAK MONTH									
1 – 25%	15	17	10	7	11	27	11	0	3
26 – 50	0	26	0	3	9	20	24	0	0
51 – 75	1	2	0	2	1	3	15	0	0
76 – 100	4	0	0	0	0	0	5	0	1
0	43	18	53	51	42	13	8	0	59

Table 2 and Figure 4 also demonstrate that companies tend to employ a multiple-source supply strategy in increments often amounting to 50 percent or less of their total supply package. Besides firm pipeline transportation, other categories of gas supply were also important for peak-day deliveries by the sample of companies: 42 of 63 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, while 46 companies indicated that up to 50 percent of their peak-day supplies were city gate supplies for transportation customers. Twenty-two used on-system storage, 19 made city gate purchases, 12 utilized local production, and seven use LNG or propane air as a supply source. This year respondents did not use any interruptible transportation for their peak deliveries, whether on a peak day or within a peak month. The other category includes pipeline operational balancing agreement receipts, line pack and draft, off-system transport, and interstate supplies.

FIGURE 4



Supply diversity is not limited to the gas source. Local gas utilities also employ a diverse set of contractual arrangements to procure their gas supplies, including long-term, mid-term, monthly and daily agreements. A mix of contracts allows the LDC to balance between competing needs, such as the obligation to serve its customers as the supplier of last resort and the need to maximize efficiency while minimizing costs. In many cases, longer-term contracts contribute to baseload obligations, while shorter-term contracts allow companies to respond to market changes. However, recent developments in reduced market volatility, particularly as they apply to natural gas acquisition prices, are resulting in a reexamination by consumers and regulators of supply acquisition contracting with less emphasis on absolute least cost and more stress on price stability. Some argue that longer-term contracting may be useful to underpin new supply sources in the future.

Generally the 2011-12 data show a balance of contract lengths among all peak-day and peak-month supply volumes, particularly for volumes up to 50 percent of requirements (see Table 3). However the use of mid-term deals (defined as more than one month but less than one year) is becoming more prominent for gas volumes representative of 51 to 75 percent and 76 to 100 percent of gas requirements. Table 3 includes contract terms for winter heating season supplies and shows the increased use of monthly agreements for the five-month winter period compared to the peak-day and peak-month.

For 2011-12 WHS peak-day supplies, long-term agreements (defined as one year or longer) were used by 36 of 61 companies (compared to 29 of 49 companies last year). Of those, eleven companies used long-term contracts for more than 50 percent of their peak-day supplies. In comparison long-term deals were made for more than 50 percent of peak-day gas purchases by

1

fourteen of the 2007-08 WHS survey companies. On the other hand, only seven of last year's survey companies acquired more than 50 percent of their peak-day supplies via long-term contracts.

TABLE 3

CONTRACT TERMS FOR GAS PURCHASES
2011-12 WINTER HEATING SEASON
(61 COMPANIES)

SUPPLY VOLUME PERCENTAGE RANGES	DAILY	LONG-TERM (> 1 YEAR)	MID-TERM (1 MONTH > ≤ 1 YR)	MONTHLY	OTHER
PEAK DAY					
1 – 25%	21	20	8	18	1
26 – 50	14	5	16	6	3
51 – 75	2	4	14	3	1
76 – 100	2	7	14	2	0
0	22	25	9	32	56
PEAK MONTH					
1 – 25%	27	21	9	16	1
26 – 50	7	4	10	9	3
51 – 75	4	3	19	2	1
76 – 100	1	8	14	2	0
0	22	25	9	32	56
WINTER SEASON (60 COMPANIES)					
1 – 25%	31	20	10	22	2
26 – 50	7	7	14	6	3
51 – 75	3	3	15	3	0
76 – 100	1	7	13	3	0
0	18	23	8	26	55

Mid-term deals for peak-day purchases were made by fifty-two companies during the 2011-12 WHS—more companies than those using daily (39 companies), long-term (36 companies) or monthly arrangements (29 companies). A similar pattern emerges for peak month and winter season purchases, with shorter-term deals more represented over the winter season, particularly for volumes less than 25 percent of gas purchase requirements. The other category includes long-term pre-pay deals, storage withdrawals and other arrangements.

As to supply providers, as shown in Table 4, when asked to describe the distribution of peak-day gas purchases among suppliers, 48 LDCs identified independent marketers, the balance of supplies acquired by LDCs were distributed among producers (40 companies), producing company affiliates (29 companies), LDC energy marketing affiliates (16 companies), pipeline companies (six companies), and LDC-owned production (two companies). Pipeline purchases and LDC-owned production made up a smaller part of peak-day natural gas supplies for LDC customers. The other category includes financial marketing affiliates, asset managers, storage operators, power generators or electric utilities, producer/gatherers, and other supply aggregators.

TABLE 4
DISTRIBUTION OF PEAK GAS PURCHASES AMONG SUPPLY PROVIDERS
2011-12 WINTER HEATING SEASON
(60 COMPANIES)

SUPPLY VOLUME PERCENTAGE RANGES	INDEPENDENT MARKETER	LDC ENERGY MARKETING AFFILIATE	LDC OWNED PRODUCTION	PIPELINE	PIPELINE ENERGY MARKETING AFFILIATE	PRODUCER	PRODUCING COMPANY AFFILIATE	OTHER
PEAK DAY								
1 – 25%	12	13	1	5	12	19	16	10
26 – 50	14	2	1	0	1	8	4	2
51 – 75	14	0	0	1	0	7	7	0
76 - 100	8	1	0	0	0	6	2	3
0	12	44	58	54	47	20	31	45
PEAK MONTH								
1 – 25%	15	14	1	4	15	15	12	10
26 – 50	15	2	1	0	1	12	6	2
51 – 75	9	0	0	1	0	9	9	0
76 - 100	9	1	0	0	0	5	2	3
0	12	43	58	55	44	19	31	45

When asked whether their company used asset management agreements for any portion of its gas supply purchases during the 2011-12 winter heating season, 26 of 63 companies (41 percent) said yes. Nearly 60 percent of these companies (15 of 26) used asset management for 25 percent or less of their winter heating season supplies (see Table 5).

TABLE 5 PORTIONS OF WINTER HEATING SEASON ACQUISITIONS VIA ASSET MANAGEMENT AGREEMENTS (26 COMPANIES)	
SUPPLY VOLUME PERCENTAGE RANGES	NUMBER OF COMPANIES
1 – 25%	**15**
26 – 50	**3**
51 – 75	**1**
76 - 100	**7**

VI. Supply Pricing Mechanisms and Hedging

Pricing Mechanisms

Many factors play a role in the market pricing of the gas commodity and of transportation services, including weather, storage levels, end-use demand, pipeline capacity, operational issues, and functioning financial markets. The market fundamentals that impact price have also expanded to include interest rates, other investment opportunities, the price of other commodities and even currency exchange rates. Such broad market influences impact LDCs and other gas suppliers, making planning increasingly difficult for all stakeholders. In order to deal with the inherent uncertainty of the market, even considering that natural gas markets have demonstrated relative stability in recent years, supply planners use a portfolio approach to pricing gas supplies just as they do for supply providers and transportation options.

Along with the variety of pricing mechanisms and contract terms noted below, the notion of adding fixed-price longer-term supply contracts to company portfolio management has resurfaced as an additional tool for price stability in today's market. Even some key future gas supply projects, such as those aimed at coordinating natural gas and power generation loads, may call for longer-term demand pull contract arrangements in order to be successful.

When asked whether their company would consider including fixed-price supply deals in their 1-3 year term supply portfolio at a price near the current $5-6 per MMBtu range, if regulators approved such deals, 23 of 60 companies said yes, and 23 said maybe. One year prior, half the survey companies (25 of 50) answered yes to the same question. Of the 23 companies that answered yes this year, nine chose a percentage range of 11-20 percent of total supply for these longer-term fixed-price deals. Six companies selected 1-10 percent, three opted for 41-50 percent, two elected 21-30 percent, and two chose 31-40 percent of supply volumes. Only one company indicated that it would build over 50 percent of its total supply portfolio on long-term, fixed-price deals (in this case, 70-80 percent). With respect to preferred contract durations for such deals, 13 of the 23 companies found 1-2 year terms as optimal, six favored terms longer than two years and four preferred less than one year.

Six of the companies that answered "maybe" regarding longer-term fixed price arrangements said they would consider 11-20 percent of their supply purchases for such deals, four would opt for 0-10 percent, and three would look at 21-30 percent of supply volumes. With regard to contract durations, seven of these companies view 1-2 year as optimum, three favor longer than two years and two prefer less than one year.

When examining the natural gas purchasing practices of companies during the past several winter heating seasons, it is clear that first-of-month (FOM) index pricing dominates the market for the largest portion of supply agreements, whether short, long or mid-term. Table 6 provides a closer look at the balance of pricing mechanisms among survey respondents during the 2011-12 winter heating season.

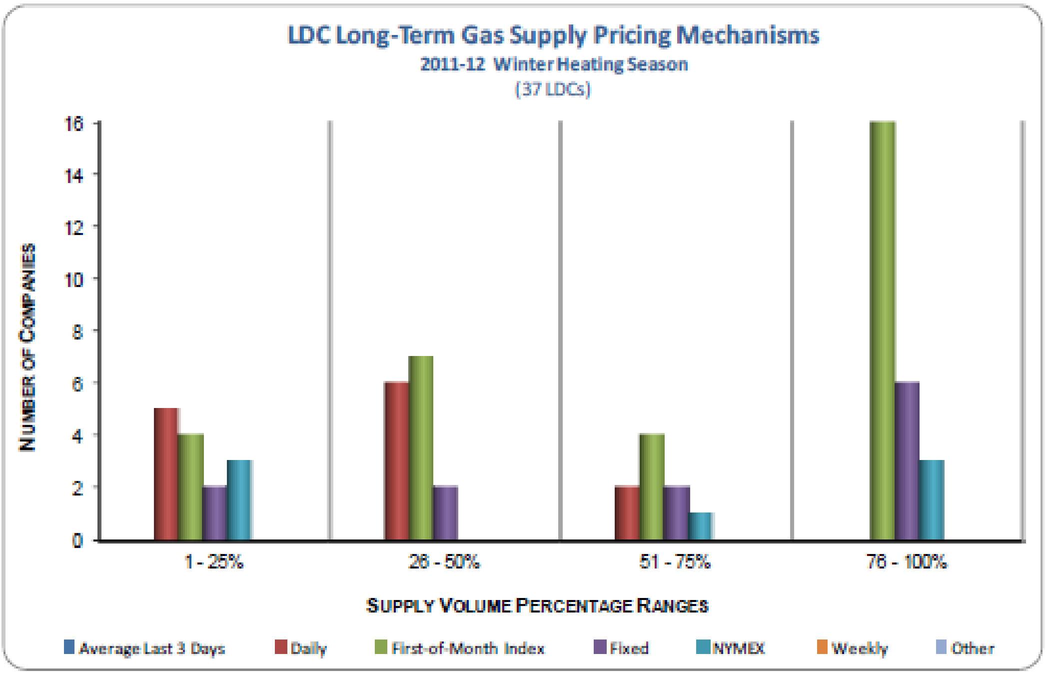
TABLE 6

GAS SUPPLY PRICING MECHANISMS – WINTER HEATING SEASON 2011-12

SUPPLY VOLUME PERCENTAGE RANGES	AVERAGE LAST 3 DAYS	DAILY (SPOT OR INDEX)	FIRST-OF-MONTH INDEX	FIXED	NYMEX	WEEKLY	OTHER
LONG TERM (GREATER THAN 1 YEAR – 37 COMPANIES)							
1 – 25%	0	5	4	2	3	0	0
26 – 50	0	6	7	2	0	0	0
51 – 75	0	2	4	2	1	0	0
76 – 100	0	0	16	6	3	0	0
0	37	24	6	25	30	0	0
MID TERM (1 MONTH > ≤ 1 YEAR – 53 COMPANIES)							
1 – 25%	0	15	3	5	7	0	1
26 – 50	0	9	9	3	4	0	0
51 – 75	0	2	14	6	2	0	0
76 – 100	0	1	16	7	2	0	0
0	53	26	11	32	38	53	52
SHORT TERM (1 MONTH OR LESS – 48 COMPANIES)							
1 – 25%	0	11	7	8	4	0	0
26 – 50	0	7	9	1	1	0	0
51 – 75	0	9	5	4	0	0	0
76 – 100	0	12	11	3	0	0	0
0	48	9	16	32	43	48	48

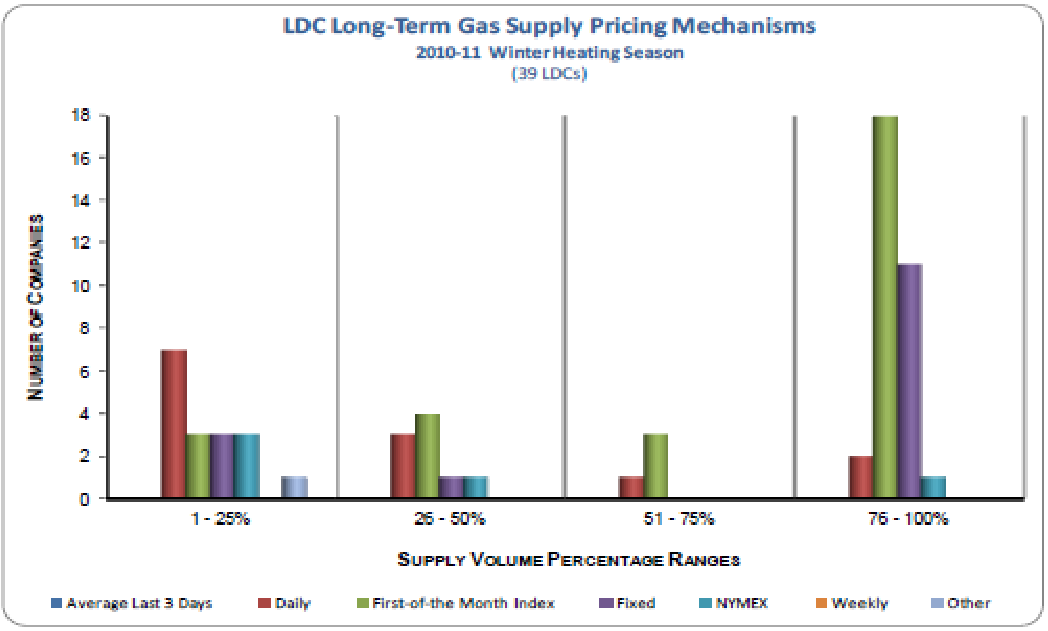
As shown in Table 6 and Figure 5, 31 of the 37 companies with long-term supplies (one year or more) used first-of-month pricing for a portion of these supplies, including twenty companies that used FOM for at least 50 percent of purchases. Thirteen companies used daily pricing mechanisms for long-term supplies, most of which used this pricing for less than 50 percent of their supply volumes. Twelve companies utilized some form of fixed pricing (compared to 15 of 39 the prior year). In comparison for the 2007-08 WHS, 15 of 47 companies used fixed pricing, while nine years ago, ten of 40 companies cited fixed deals.

FIGURE 5



Figures 5, 7 and 8 show the pricing mechanisms employed by this year's survey participants, and Figures 5 and 6 together present a comparison of long-term pricing arrangements for the past two winter heating seasons. The graphs clearly show that for larger volumes of gas purchased under long-term arrangements, first-of-month indices continue to be the predominant pricing mechanism during 2011-12 just as they were for the 2010-11 winter. This is not surprising, since the first-of-month index is not only a measure of market movement but also often serves as baseline from which hedging strategies can be measured. Fixed pricing also played a somewhat more prominent role for larger long-term volumes relative to other mechanisms. The relative prominence of these two pricing mechanisms may be explainable with the apparent development of relative price stability in the natural gas market given the overall strong natural gas supply position as demonstrated by year-to -year growth in domestic production for five years straight. Weekly and average three-day pricing played no role in long-term gas purchases during the 2011-12 WHS.

FIGURE 6



According to the 53 companies that had mid-term supplies (of more than one month and less than one year) during the 2011-12 WHS, much of these natural gas purchases were tied to FOM indices. However, as Table 6 and Figure 7 indicate, daily, NYMEX and fixed pricing mechanisms were used for smaller-volume mid-term purchases. Twenty-one companies reported using fixed pricing mechanisms for mid-term purchases, compared to 12 for long-term purchases. Also 27 companies used daily prices for mid-term purchases, compared to 13 for long-term purchases.

As would be logical, short-term purchases (one month or less) for the 48 companies that had such supplies during the 2011-12 WHS included more daily pricing (39 companies) than mid-term and long-term purchases; however, these short-term purchases were also heavily dependent on first-of-month indices (32 companies) and were also tied to fixed prices and NYMEX indices (see Table 6 and Figure 8). It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior and anticipated experiences. Even state regulator-approved pricing mechanisms may appear favorable one year while less so the next. Flexibility and constructive policy reviews, rather than second-guessing, can have a positive effect on the delivery of natural gas and services to customers at the lowest possible cost.

FIGURE 7

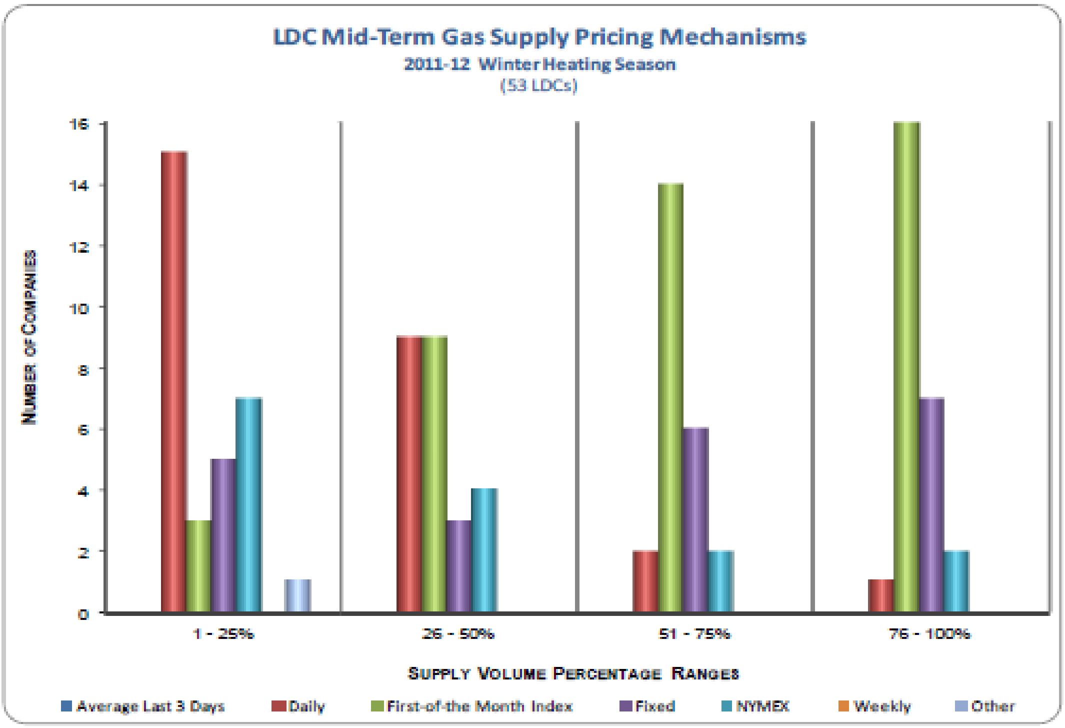
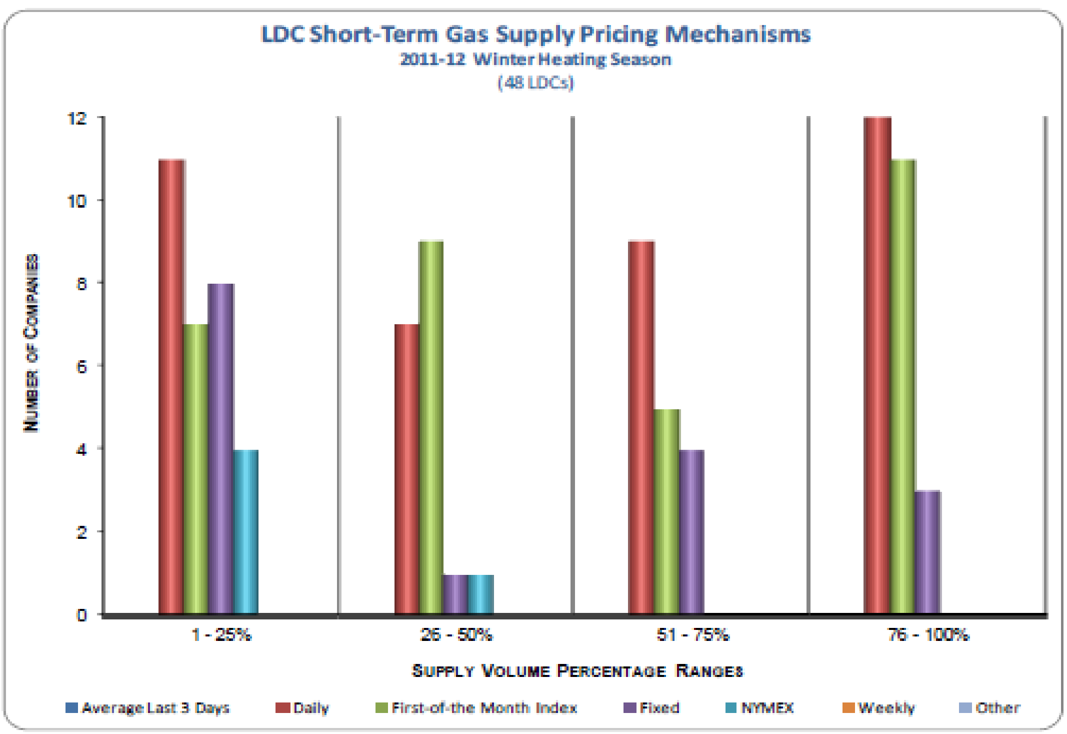


FIGURE 8



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Hedging Mechanisms

Market developments during and since the 1990s have expanded the options for acquiring gas supply, trading transportation capacity and using financial instruments. Today industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which include fixed-price gas purchase contracts, futures, swaps and options, allow gas supply portfolio managers to hedge or lock in a portion of the commodity cost component of gas supplies. This is accomplished well when the required level of risk and the rewards or benefits of managing such risk are properly balanced by the company, consumers and regulatory bodies.

Eighty-one percent of responding companies (51 of 63) said they used financial instruments to hedge a portion of their 2011-12 winter heating season gas supply purchases. This percentage is lower than in the past three years, where 92 percent of companies reported using financial tools in 2010-11, 90 percent in 2009-10 and 89 percent in the 2008-09 winter heating season. Still this percentage is significantly larger than in 2004-05 (70 percent of respondents) and in 2001-02 where only 55 percent of respondents reported using financial tools to hedge gas supply costs. It is important to note that the company makeup and size of the survey sample differ from year to year. For this past winter, 34 of the 51 companies hedged up to 50 percent of their gas supply purchases (comparable to the 34 of 47 companies for the prior winter).

Respondents used one or more of the following instruments to hedge a portion of their 2011-12 WHS gas supply purchases: fixed price contracts (26 companies), options (26 companies), swaps (22 companies) and futures (14 companies). The use of financial instruments may be understated in this report inasmuch as some of the volumes delivered to LDCs from marketers and other suppliers are hedged by a third-party rather than the LDC and may have been excluded from the LDC's data. Only four of 63 companies reported using weather derivatives during the 2011-12 winter heating season. This compares to two of 51 companies in 2010-11, five of 76 companies in 2006-07, and seven of 54 in the 2004-05 survey.

When asked about the timing of hedging strategies, 42 of 51 of the companies with hedging programs (82 percent) indicated that they applied a six-month or less strategy for a portion of their hedges for the 2011-12 winter heating season. Forty-three companies used a 7-12 month strategy, and 27 companies employed a greater than 12-month strategy. Of course, a single company may use one or all strategies simultaneously. In fact, 23 of the respondents did just, compared to 19 the prior year.

Thirty-seven of the survey companies indicated that for the upcoming (2012-13) winter heating season, they planned to hedge at the same level as in this past season. One company plans to hedge to a larger extent than it did for this past winter (compared to three and two companies in the 2010 and 2011 surveys respectively), and eleven intend to hedge less.

On the physical side, companies view gas supplies delivered to storage during the summer refill season as a price hedge against potential winter run-ups. In preparation for the 2011-12 winter heating season, 61 of the 63 reporting companies (97 percent) used storage as a physical hedge (compared to all 51 and 56 reporting companies in the 2011 and 2010 surveys, respectively). Fifty-three companies reported using storage for up to 50 percent of 2011-12 winter heating season supplies compared to 52 and 46 companies for the 2009-10 and 2010-11 winter heating seasons, respectively.

In some jurisdictions there are no formal standing plans. In others, LDCs may actually be required to hedge portions of future gas supplies with those hedges required to be in place by predetermined dates. Variations on these themes are many and are geared to fit the interplay among a local distribution company, the regulator and market conditions in a given area.

When asked about their regulatory environment, the majority of respondents (53 of 60) reported no change in their regulator's receptivity to financial hedging during the 2011-12 winter heating season compared to prior years, and one reported increased receptivity on the part of its regulator or public utility commission (PUC). Five companies indicated that their PUC was less receptive this past winter heating season.

Of the 63 reporting companies, 17 noted that their regulator required a hedging plan to be filed for approval. In addition, twenty companies indicated that state regulators place restrictions on hedging parameters, such as choice of financial tools, date ranges and/or the quantities hedged. Of these companies, three indicated that their regulator requires both a plan and restrictions on hedging. Twenty-nine of the respondents noted that no plans or restrictions were required for their programs.

All fifty companies with hedging programs that answered the question reported that their regulator treated financial losses and gains from hedging equally. This 100 percent response compares with 88 percent (or 45 of 51 companies) one year ago, 81 percent the year prior, and 78 percent the year before that. Additionally, 49 of 51 companies answered yes when asked if costs associated with their financial hedging programs were fully recoverable, and two respondents answered that up to 100 percent of their costs could be recovered but it is not guaranteed.

When asked about the focus of their regulator with respect to natural gas acquisitions, twelve respondents indicated that their regulator was primarily interested in the lowest possible price, nine said that the focus was on stable prices, and 35 companies said their regulator was equally concerned with both low and stable prices.

Among LDCs, motivations vary behind hedging programs. When asked how customers benefited from their financial hedging compared with no hedging, 41 of 51 companies (80 percent) noted the reduced volatility in prices was a major benefit to customers, two cited reduced gas costs as the main advantage to customers, and four observed both effects for their customers. Companies were also asked whether they offered customers fixed-price options during the 2011-12 winter heating season, and eight of 63 said yes.

Within the context of a portfolio approach to gas acquisition and price management, companies were asked to identify the most effective tool they used to manage supply availability and price risk during the past winter heating season. Physical storage was on the top of the list for 28 of the 57 companies that provided answers. Also noted were fixed price contracts, physical call options, index price contracts (FOM and daily), collar and swing options, and dollar cost averaging—in that order. As to the risk management products they would have liked to have used more of, companies mentioned storage, additional financial hedging (including NYMEX swaps and call options), asset management programs, long-term purchases (i.e. reserves), daily purchases, and greater late season flexibility.

VII. Gas Storage

As noted earlier, local distribution companies are concerned with managing gas supply and transportation portfolios efficiently and to reduce costs. Production area storage and market area storage can help LDCs meet such goals. The use of storage facilities helps LDCs to both meet short-term swing opportunities and satisfy peaking needs. Table 7 shows storage levels as estimated by the Energy Information Administration for January- April 2011 compared to the same period in 2012.

TABLE 7

AMERICAN GAS STORAGE SURVEY
WORKING GAS IN STORAGE

2011 (Bcf)					2012 (Bcf)				
	Total	Prod	East	West		Total	Prod	East	West
Dec 31, 2010	3097	1079	1590	428	Dec 30, 2011	3472	1195	1830	447
	2959	1059	1510	390		3377	1179	1754	444
	2716	968	1384	364		3290	1164	1693	433
	2524	912	1280	350		3098	1121	1561	406
	2353	856	1165	332		2966	1099	1471	396
Feb 4	2144	789	1055	300	Feb 3	2888	1088	1412	388
	1911	698	937	276		2761	1051	1329	381
	1830	687	880	263		2595	993	1232	370
	1745	696	809	240		2513	974	1174	365
	1793	708	793	292					
Mar 4	1674	703	748	223	Mar 2	2433	967	1114	352
	1618	700	697	221		2369	965	1059	345
	1612	715	675	222		2380	985	1049	346
	1624	740	668	216		2437	1019	1074	344
						2479	1045	1085	349
Apr 2	1579	742	616	221	Apr 6	2487	1042	1092	353
	1607	763	623	221		2512	1049	1105	358
	1654	780	652	222		2548	1041	1145	362
	1686	793	666	226		2576	1040	1165	371

Source: Energy Information Administration

For the nation as a whole, working gas inventories in both years were not strained, even though by the time net injections began in earnest in mid-April 2011 working gas levels were about 175 Bcf behind that of April 2010. For season's end in 2012, however, the mild winter conditions and the strength of domestic natural gas production resulted in remaining working gas volumes at month-end March virtually at record inventory levels for the time of year.

The short-term market result of strong season ending storage inventories has been that instead of a starting point requiring 10-12 bcf per day of net injections to refill storage during the 2012 summer, requirements fell to 7 Bcf per day with most of the comparative balance going to power generation during a very warm summer with almost no influence on market acquisition prices. Put mildly, 2012 has been an extraordinary year for natural gas markets.

Going back to the 2011 spring-summer storage refill season in preparation for the 2011-2012 winter heating season, however, operational issues and supply reliability requirements were at the top of the list of reasons for LDCs to inject gas supplies into storage injections: These two issues were equally cited by 95 percent of companies (58 of 61). Price considerations also influenced the decisions of 46 companies, and regulatory plans or mandates impacted the storage strategy for 26 companies. Of course, more than one variable may influence injections of gas supplies into storage: In fact, 20 of the companies were motivated by all four factors. When asked whether their company flowed gas from storage to serve gas-fired electric generation load at any time during the storage injection season (April – October), 19 of the 58 companies to which the question applies said yes, compared to 15 of 51 the prior injection season.

A variety of reasons also underlie LDCs' decisions to use their existing available stored gas supplies. Weather-induced demand compelled 98 percent of respondents (60 of 61) to make use of their storage services during the 2011-12 winter heating season. Other influencing factors cited by companies were no-notice requirements (51 companies), "must turn" contract provisions (38 companies), pipeline operational flow orders (24 companies) and arbitrage opportunities (22 companies). Again more than one variable moved companies to use storage: Ten of the companies said that they were influenced by all five reasons.

Table 8 and Figure 9 show that many of the gas purchases made for storage injections during the 2011 refill season, in preparation for the 2011-12 winter heating season, were based primarily on first-of-month indices (52 companies; however, daily, fixed price and even NYMEX-based gas pricing were also prevalent, particularly for small volumes of gas destined for underground storage.

TABLE 8
PRICING MECHANISMS FOR GAS INJECTED INTO UNDERGROUND STORAGE
2011 STORAGE REFILL SEASON (APRIL THROUGH OCTOBER)
(60 COMPANIES)

SUPPLY VOLUME PERCENTAGE RANGES	AVERAGE LAST 3 DAYS	DAILY (SPOT OR INDEX)	FIRST-OF-MONTH INDEX	FIXED	NYMEX	WEEKLY	OTHER
1 – 25%	1	25	5	18	10	0	0
26 – 50	0	8	11	4	6	0	0
51 – 75	0	3	15	2	2	0	0
76 – 100	0	4	21	5	0	0	1
0	59	20	8	31	42	60	59

The same is reflected in Figure 10 for the refill period in 2009. Looking back, we find that in 2007 twenty-seven of 57 companies indicated that more than 75 percent of supplies purchased for storage injections were FOM priced, in 2008 twenty-three of 53 companies and in 2009 19 of 55 companies did the same in 2008 and 19. Fixed price schedules accounted for storage volumes injected by 26 companies reporting for 2010, while daily pricing applied to 30 of the surveyed companies. Daily pricing was generally applied to 1-25 percent of gas purchased for underground storage in 2009 but also up to 50 percent in 2010.

Regarding future plans, twelve companies indicated that during the past winter season they considered the option to build underground storage additions during the next five years, of which three were in the building process. In addition, nine companies considered additions or expansions of market-area LNG or propane air peak-shaving facilities, of which one was in the building phase. With respect to contracted storage capacity, only six companies plan to increase underground storage for the 2012-13 winter heating season, while three will decrease storage capacity. Additionally, one company plans to contract for additional peak-shaving capacity for the 2012-13 WHS.

FIGURE 9

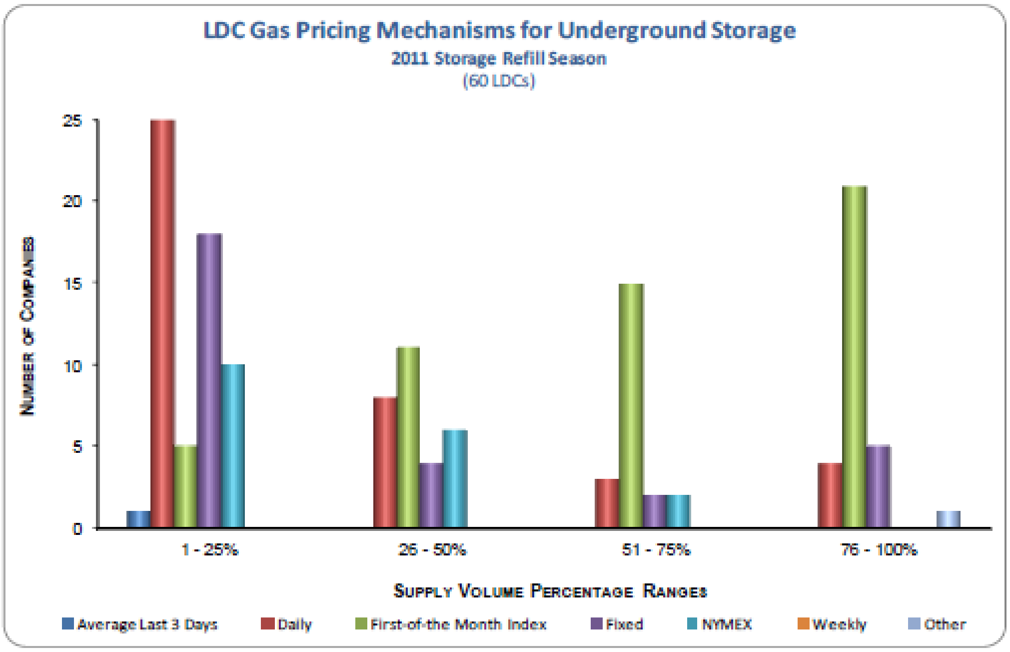
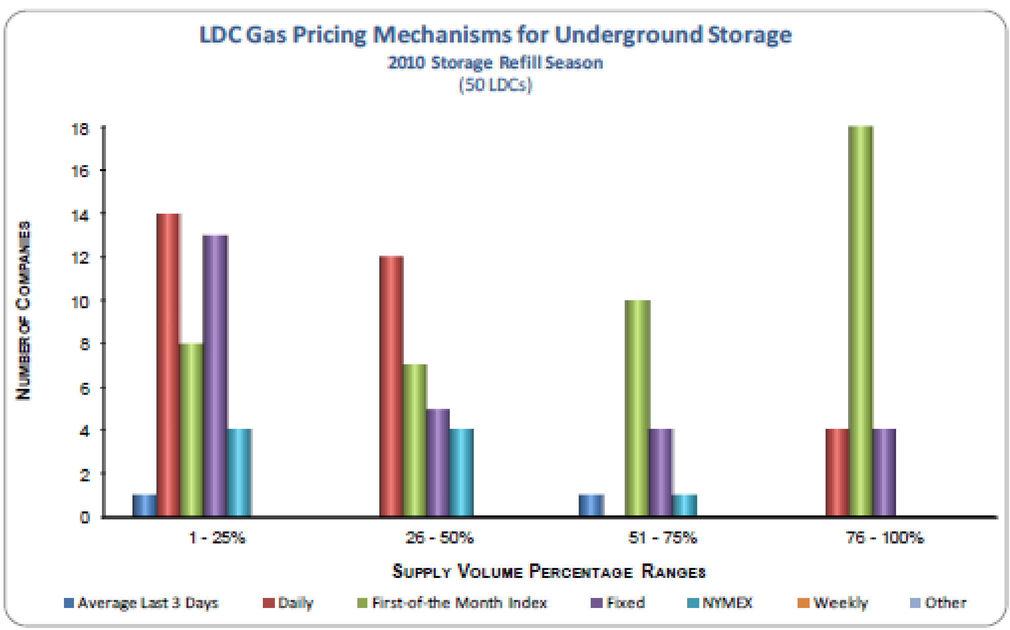


FIGURE 10



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Respondents were asked how they managed storage assets during the period of November 2011-March 2012, given that this past winter heating season was 17 percent warmer than normal nationally and working gas in storage was 60 percent higher than the 5-year average at the end of the withdrawal season. Twelve of the 63 respondents indicated that that they employed non-traditional methods to strategically manage storage assets, including 1) conducting an economic review of must turn provisions and selling base winter supply to meet storage withdrawal requirements, 2) hedging storage, optimizing storage to reduce Weighted Average Cost of Gas and prioritizing all ratchet based storage over other options, 3) the interstate pipeline relaxing late season ratchet, 4) acquiring short-term interruptible storage, 5) purchasing less flowing supplies each month, and 5) continuing injections of flowing gas sources into the standard storage withdrawal period.

Nine companies indicated that the historically high storage inventories would impact how they strategically manage storage assets during the upcoming injection season and that critical issues are anticipated, while six companies said maybe this would occur. Some expect less space for injections during August through October, and others anticipate OFOs and some expect storage owners to issue those earlier in injection the season. Contingency plans include 1) not purchasing as much bid week for storage fills, 2) purchasing less long term and more daily and monthly supply, 3) lowering November 1 starting inventory targets to accommodate supplies in the event of a warmer winter, 4) expecting to significantly reduce injections and to align with best pricing opportunities, and 5) considering potential Park/Loan services.

VIII. LDC Transportation and Capacity Issues

Transportation-only customers have assumed a higher profile among customers served by LDCs. As stated before, planning for transportation capacity and supply is generally held hostage to weather, economic activity and other factors that influence gas consumption. Managing pipeline capacity efficiently is a challenge for LDC's and may involve the release of capacity to the secondary transportation market, if events allow it.

Table 9 presents a brief view of this topic. LDCs were asked to identify the percentage of pipeline capacity they held and released to the secondary market each month from April 2011 to March 2012. This table highlights some interesting elements. The majority of respondents consistently released less than 25 percent of their capacity throughout the year. As might be expected, during the spring-summer months, more companies made up to 50 percent of their releasable capacity available to the secondary market—which makes sense given that LDCs are less likely to have a large excess of capacity during the winter heating season months as they try to meet seasonal heating loads.

In addition to the above data, 30 of 63 companies used capacity held on *non-affiliated* interstate pipelines to make off-system wholesale natural gas sales. Only two companies used capacity held on *affiliated* interstate pipelines to conduct wholesale natural gas transactions.

Regarding system operations, 29 percent of survey respondents (18 of 63 companies) indicated that their operations and/or system had been impacted by the issuance of pipeline operational flow orders (OFOs) during the 2011-12 winter heating season. This compares to 37 percent during the prior winter and 41 percent during the 2009-10 WHS. Looking further back, at the 2002-03 and 2003-4 winters, 74 percent (48 of 65) and 51 percent of respondents, respectively, reported contending with such OFOs.

TABLE 9
PERCENT OF PIPELINE CAPACITY RELEASED BY LDCS
2011-12

CAPACITY PERCENTAGE RANGE	INJECTION SEASON							REFILL SEASON				
	2011									2012		
	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR
1 – 25%	27	29	29	28	29	28	30	25	26	26	28	25
26 – 50	8	8	7	8	7	7	7	5	5	5	4	7
51 – 75	3	2	3	3	4	4	3	0	0	0	0	0
76 - 100	3	4	4	4	4	4	3	4	4	4	4	4
0	27	29	29	28	29	28	30	25	26	26	28	25

The 18 companies in the 2012 survey reported between one and forty OFOs, and the median number of issuances was 5.5. Duration for the OFOs ranged from one to thirty days; however, the median duration was two days. Reasons for the OFOs had to do mainly with protecting system integrity and maintaining pipeline physical flow requirements, and they were in response to scheduled volumes exceeding physical capacity, low gas flows, and equipment failure. Only one company reported being limited by a Critical Day for storage withdrawals—five of them, and they lasted two days on average.

IX. Local Gas Utility Regulatory, Rates and Other Issues

Examining other regulatory issues, survey participants were asked if regulators in their state(s) of operation were formally investigating their gas acquisition prices for the 2011-12 winter heating season. Thirty-five of 63 companies responded in the affirmative, however, all described the investigations as *routine*. In addition, when asked whether regulators had significantly delayed the full recovery of gas sales costs incurred during the 2011-12 winter, all 63 survey companies said no.

The method for recovering gas costs was further described: for thirty-five of 63 companies, gas costs that are incurred over a period of time are passed through to customers, and over-or under-recovered costs are deferred, with interest, and collected or distributed during a subsequent period. For some companies, recovery is subject to a prudence review. Twenty-one companies have a similar approach to gas cost recovery, except interest is not applied to the deferred amounts. For four companies, the addition of interest depends on whether the gas costs have been under or over-recovered from customers, while for one other company the treatment of interest varies by jurisdiction in which it operates. Two companies mentioned other recovery mechanisms, including a defined sharing of gains and losses structure and a PUC-approved incentive mechanism governing cost recovery.

When asked whether permitted to retain a part or all of their revenues from off-system wholesale natural transactions, 25 of the 41 companies to which this question applies said yes. In addition, of the 63 survey companies, twenty-eight are permitted to use weather normalization clauses within their rate structures.

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I. APPENDIX D – MEMORANDUM SUMMARIZING CUSTOMER'S PERSPECTIVE

The purpose of this memorandum is to summarize key findings gained from interviews Concentric held with representatives of Gaz Métro's key consumer groups. Concentric undertook these interviews to better understand customers' needs regarding price stability, protection against sharp price increases, and their sensitivity to the cost of the financial derivatives programs as well as their perception of its benefits. Concentric conducted four interviews with representatives of the following organizations: The Féderation canadienne de l'enterprise indépendante ("FCEI"), Option consommateurs ("OC"), Union des consommateurs ("UC"), and the Union des municipalités du Québec ("UMQ"). We also requested an interview with the Association des consommateurs industriels de gaz ("ACIG"), but the request was declined on the basis that virtually all industrial users purchase their commodity from third party marketers and have not been exposed to Gaz Métro's system gas supply costs.

Concentric provided interviewees with a sample of questions that we intended to discuss during the interview. The questions were organized in three groups: the Intent of the Program, Alternative Program Elements, and the Benefits and Costs of the Program. All interview participants were extremely helpful in providing their responses and perspectives on the Program. The answers to our questions are summarized below:

All interview participants indicated that their involvement with the Program was limited. Each group falls within the range of occasional intervener in relation to the hedging Program, at one end of the spectrum, to a regular intervener in Gaz Métro's rate proceedings, on the other end. Each understands that there are significant costs related to the financial derivatives Program that may not have provided proportional benefits to ratepayers. The interveners were very supportive of engaging an expert to review the Program and are very interested to see how other utilities in North America are responding to similar challenges and to gain a perspective on what may be best practices for utility hedging programs. There was some discussion that the utility hedging Program had not been well understood among customers and interveners since it has been buried within the regulatory incentive regulation process, and without regular rate proceedings, it had been very difficult to scrutinize the costs and benefits of the Program. Some interveners called for easier access to cost/benefit data and more transparency around the activities of the Program.

Intent of the Program

The questions posed to interviewees in this segment of the interview addressed the objectives of a utility hedging program and what it should strive to accomplish and conversely what it should not strive to accomplish. How important is it for customers to be protected against large price spikes? How important is price stability? Can the customer tolerate prices under the Program that exceed market prices or should the costs of gas under the Program provide the least cost alternative? The responses were generally as follows:

- Should Gaz Métro have a program to manage volatility in natural gas prices? Though none of the interveners interviewed called for the termination of the Program, all indicated that the Program should be more cost effective. The consensus answer is that the benefits of the Program should support its costs. It was generally agreed that some protection against price spikes should continue to be provided, but that it is important to understand the current volatility in the market, and the range of reasonable expectations for price. Interveners expressed that if the range of expectations for price is not outside of tolerances, than hedging does not provide much benefit. They would like to better understand the range of prices that customers were insured against and how Gaz Métro is conducting its hedging activities. All agreed that with the currently low natural gas prices, it is less important to hedge than it has been in the past, especially since natural gas now enjoys a slight competitive price advantage over hydroelectric power in Quebec. What is important is that Gaz Métro has a Program that is well managed and achieves the objectives that it sought to achieve.
- How important is it to ensure price stability? What are the consequences of a sharp rise in prices or high variability of rates? First, it is important to note that Gaz Métro has a diverse customer base and the protection that is required varies among customer groups. There is a sizeable amount of multifamily, bulk-metered properties, which have a low-income component that would most likely be considered small commercial customers. Low-income customers inhabit old inefficient gas-heated homes and are unable to change their consumption but are extremely price sensitive. They do not have any options to manage their gas price volatility. They are captive customers in the truest sense and though they are the least able to bear the incremental costs of hedging, they are the most in need of price protection. Other customers such as municipal customers and small businesses place the

emphasis on predictability. They would most like price certainty and prefer a multi-year, fixed-rate option. A longer-term fixed-rate option could be attractive to many customers, i.e. landlords subject to rent control, fixed income customers, small business. Still other customers would prefer a range of options from minimal to no hedging, to more robust hedging to a fully-hedged, fixed-price program. However, there was some concern over the customers' aptitude to make an informed decision.

- What is a reasonable amount to pay for insurance; and what increase in the overall gas bill should a hedging program protect against? Though there was some reluctance to attempt to quantify the cost one may be willing to bear for hedging or the price or bill increase that should be protected against, a few interveners did offer their perspective. Some thought between $20 to at the highest $100 per year, was a reasonable price to pay for price stability. A 3 to 5% increase in the overall gas bill was determined by at least one intervener to be "important". A much larger increase in gas prices would be necessary to result in a 3 to 5% increase in the overall gas bill.
- What should the objectives of a hedging program be? What should not be objectives of a hedging program? Generally all interveners agreed that there should be some protection against catastrophic prices and major price fluctuations or spikes. Others emphasized the need for price certainty and indicated that there would be interest in a fixed-price gas supply tariff option offered by the gas utility. All agreed that the Program should be sufficiently responsive such that if prices did begin to increase the hedging program would adapt accordingly. Though some interveners indicated that preserving the competitive position of natural gas over hydroelectric electricity might be important to Gaz Métro, it generally was not an important objective from the consumers' perspective. Consumers want to pay the least price for their energy and Gaz Métro's ability to retain its competitive position in the energy market was not seen as directly serving customers' needs.
- Should the Program provide the most cost effective solution for system gas users? There was some recognition that incremental hedging costs may not result in direct financial benefits to the consumer and that providing price protection comes at a cost. But, the cost should not be onerous and should be adapted to the market circumstances such that it may capture opportunities in a declining market. Interveners indicated that they would like to be presented with options, ranging from less hedging to more hedging; and that the insurance provided should reflect the risk tolerances of its consumers.
- How far in advance should the Program look to create price stability and to reduce rate volatility? Though not all interveners had an opinion on this, those that did indicated that there was interest in a fixed-rate tariff option locking in prices for a period ranging from 1 year to 3 years. A hedging horizon of between 2 and 3 years was thought to be appropriate among those who commented. One intervener commented that a hedge horizon of four years was appropriate, but that a shorter period may be preferable given market circumstances. There was concern with hedging too far out into the future given the

dynamic nature of natural gas markets, and how much they could change in that time frame. Five years was considered to be too far out.

Alternative Program Elements

This segment of the interviews attempted to understand the available alternatives to a formalized hedging program for managing price volatility for consumers. The questions and responses were roughly as follows:

- Do you know of alternative methods others are using to create price stability? Acknowledging that this may be a significant departure for Gaz Métro, interveners liked the option of having a fixed-price, multi-year tariff. One intervener mentioned that although commercial customers have the option of transacting a fixed-price agreement with a 3rd party marketer, most customers won't go out of their way to seek a fixed price and tend to accept the commodity price as something they have little control over. Many commercial customers would favor a fixed-rate tariff option. There was some concern that bulk-metered residential customers that currently are billed for their gas usage through a rent charge, cannot be assured that market opportunities are passed on to them. Though price increases will be passed on through rental rates, there was some skepticism as to whether renters would ever realize the benefit of price decreases. It would seem that for these customers price certainty may also be important.
- If the Program has an element of customer choice, the interveners expressed some concern over how much information people would digest to make an informed appropriate choice. Would consumers pay more to lock in a fixed price? Historically, they have only wanted to pay the minimum. Highly price-sensitive consumers may be interested in a monthly payment plan or a rate smoothing program.
- One intervener mentioned that they might like to see more use of storage capacity, which in their opinion would allow for more flexibility.
- Some system gas customers could manage volatility by fuel-switching. But it was acknowledged that in most cases, switching had already occurred such that there is not much opportunity for further switching without significant retrofitting costs. Switching from electricity to natural gas can be difficult and expensive, since natural gas requires extensive duct work. Switching from heating oil to natural gas on the other hand is relatively easy. Switching from natural gas to electricity has an associated cost but is easier than switching from electricity to natural gas.
- What would happen if Gaz Métro were not allowed to continue its hedging Program? It is generally understood that without some sort of hedging program, there is no way for

residential consumers to protect themselves from natural gas price spikes. Though the consensus was that there must always be some degree of price protection for the captive rate payer, i.e. the minimum cost price protection that protects against extreme price spikes, at least one intervener expressed skepticism that price protection was actually being passed on to the majority of low-income customers, since most are at the mercy of their landlords and the rent control board. Though it was acknowledged that rent increases may be capped by the rent control board, there is no obvious mechanism to pass on decreases or market benefits in a declining market. As such, this intervener saw little value to hedging for at least the portion of system gas customers that pay for gas consumption through their building rent.

Benefits and Costs

In the final segment of the interview, we asked participants about the costs and the benefits of the Program. We also asked how best to measure the benefits or the performance of the Program. Below we have summarized the responses we received to those questions:

Is the Program currently providing benefits to customers? Generally, all interveners felt that the Program was too costly and given the developments in the natural gas market, the cost of hedging was not providing benefits to customers. They noted that many provinces and state regulatory commissions have suspended hedging programs for these same reasons. Interveners believe that in today’s market it is not worthwhile to insure against small or tolerable price fluctuations.

What is a reasonable way to assess if the Program is being efficiently executed; what sort of metrics would be helpful to understand and receive on a regular basis from Gaz Métro? Interveners indicated that it would be helpful to know how the Program performed relative to benchmarks, perhaps against other Northeastern regulated utilities. The interveners would like to see greater transparency around the costs of the Program, and a better understanding of what is fixed and what is variable? Generally all would like to see some sort of cost benefit analysis to support the Program; and a sensitivity analysis of how the Program would have performed under varied price scenarios. If customers were given a choice on rate options, it would be interesting to see how they are making their choices. Ultimately, it seems that all interveners were in favor of the customer choosing to be more hedged than the minimum.

Does your perspective of the Program change with the level of gas prices or the associated level of volatility? One intervener shared the following perspective: The basic program objectives should be maintained, but the allocation or weighting of each objective should change in response to market conditions. That would indicate that the distributor is following the market and has realigned the program objectives proportionately to fit market conditions. It is best if the distributor has a Program that is responsive to all market conditions, rather than closing and reopening the Program if market conditions change at some later date. It was offered that forward market expectations with respect to price and volatility should play a role in determining the appropriate hedging strategy. Others declined comment on the basis that they did not possess the appropriate expertise.

Is the volatility of gas prices a determinant to customers switching from electricity to natural gas? Yes, but it would generally require a major renovation to make the switch. Most customers that could easily switch have already done so. Even if gas prices were a little higher than hydro, gas customers wouldn't switch because it would cost a few thousand dollars to convert. Only if gas prices went much higher for an extended period, would customers be able to recoup their costs. Switching is mostly for the big customers.

Concluding Thoughts

Interveners generally acknowledged that the Program should provide some minimum, inexpensive catastrophic protection for its captive consumers. However, there was a fair amount of consensus around the prospect that the current level of protection may be excessive in the current market context. All agreed that the forward expectation for natural gas markets is for low volatility and low prices; and under these conditions, only the minimum amount of hedging should be conducted so that the consumer could more fully realize the benefit of market declines. Though some made recommendations, for a fixed priced tariff or to expand the use of storage capacity as an alternative to the current Program, there was little acknowledgement that those types of programs could also result in significant hedging losses to customers if program costs are measured by the variance of gas costs to market prices. However, there was a great deal of support for the prospect of the consumer selecting the level of hedging they desired, thus allowing consumers to choose their program requirements in accordance with their own risk tolerances.

Appendix J

COMMISSION ORDER G-120-11

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-120-11

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc.
(collectively Terasen Gas) (now FortisBC Energy Inc. and FortisBC Energy (Vancouver) Inc.)
for Approval of the Price Risk Management Plan Effective April 2011–October 2014

BEFORE: D.A. Cote, Panel Chair/ Commissioner
L.A. O'Hara, Commissioner
N.E. MacMurchy, Commissioner

July 12, 2011

O R D E R

WHEREAS:

A. On July 22, 2010, the British Columbia Utilities Commission (Commission), by Orders E-23-10 and E-24-10, denied the 2010 Price Risk Management Plans submitted by FortisBC Energy Inc. (FEI) and FortisBC Energy (Vancouver Island) Inc. (FEVI) respectively. In letters which accompanied the Orders, the Commission directed FEI and FEVI, in consultation with Commission staff, to conduct a review of the PRMP's primary objectives in the context of the *Clean Energy Act* and increased domestic natural gas supply;

B. On January 27, 2011, FEI filed with the Commission on a confidential basis the "Review of the Price Risk Management Objectives and Hedging Strategy" providing the results of the FEI review of the of the PRMP objectives and the recommendations of its consultant, RiskCentrix, LLC for an enhanced hedging strategy;

C. On January 27, 2011, FEI also filed with the Commission on a confidential basis the "Price Risk Management Plan Effective April 2011–October 2014" (2011 PRMP or Filing) for approval of the objectives and key elements of the 2011 PRMP which include measures for programmatic, defensive, and value hedging as well as basis swaps to hedge price exposure at the Sumas trading hub;

D. The Commission reviewed the Filing and concluded that prior to making a determination on the need for a hedging program, a written process was necessary to review the objectives of the 2011 PRMP;

E. On February 18, 2011, FEI filed redacted copies of the 2011 PRMP and Review of the Price Risk Management Objectives and Hedging Strategy suitable for public review;

F. On February 22, 2011, the Commission issued Order G-23-11 establishing a Written Public Hearing process (the Proceeding) with a Regulatory Timetable to review the objectives of the 2011 PRMP;

G. Order G-23-11 approved FEI at its discretion over the course of the proceeding to, on an interim basis, implement those measures related to value hedging, programmatic hedging and Sumas basis swaps as outlined in the 2011 PRMP;

H. Effective March 1, 2011 Terasen Inc. changed its corporate name to FortisBC Holdings Inc. such that Terasen Gas Inc. became FortisBC Energy Inc. (FEI) and Terasen Gas (Vancouver Island) Inc. became FortisBC Energy (Vancouver Island) Inc.;

I. The Commission has considered the Filing, submissions and evidence provided by FEI/FEVI.

NOW THEREFORE the Commission, for the Reasons attached as Appendix A orders as follows:

1. With the exception of the Sumas/AECO Basis Swaps element the FEI 2011-2014 PRMP Filing is denied.

2. FEI is encouraged to consider alternate means of augmenting the existing non-PRMP tools used to manage natural gas price volatility as discussed in the attached Reasons for Decision.

3. FEI is directed to properly manage its existing PRMP portfolio positions in a prudent manner to expiry, unless otherwise directed by the Commission.

DATED at the City of Vancouver, in the Province of British Columbia, this *12th* day of July 2011.

BY ORDER

Original signed by:

D.A. Cote
Commissioner

Attachment

IN THE MATTER OF

FORTISBC ENERGY INC. AND
FORTISBC ENERGY (VANCOUVER ISLAND) INC.
2011-2014 PRICE RISK MANAGEMENT PLAN

REASONS FOR DECISION

July 12, 2011

BEFORE:

D.A. Cote, Panel Chair / Commissioner
L.A. O'Hara, Commissioner
N.E. MacMurchy, Commissioner

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APPENDICES

1.0 INTRODUCTION

1.1 The Filing

Both FortisBC Energy Inc. (FEI), formerly known as Terasen Gas Inc. and FortisBC Energy (Vancouver Island) Inc. (FEVI), formerly known as Terasen Gas (Vancouver Island) Inc. (collectively the Utilities or FEU) as is the traditional practice, file separate annual Price Risk Management Plans (PRMP) seeking approval of gas commodity hedging plans for the next three year period and, in the case of FEVI, for the next five years. In May of 2010 both FEI and FEVI submitted their PRMPs for review and acceptance by the British Columbia Utilities Commission (BCUC, Commission). On July 22, 2010 BCUC issued Order E-23-10 and Order E-24-10 which denied the PRMP Applications of FEI and FEVI. In addition, these Orders directed the Utilities to conduct a review of the primary objectives of the PRMP in the context of the *Clean Energy Act (CEA)* and the increase in domestic natural gas supply. Further, on the basis of discussions held with Commission staff FEU also agreed to expand this review by examining the cost/benefit value of hedging for customers. (Exhibit B-1, p. 4)

On January 27, 2011 FEU filed with the Commission on a confidential basis the "Review of Price Risk Management Objectives and Hedging Strategy" (Review Report) which included the results of its review of the PRMP objectives and an enhanced hedging strategy based on the recommendations of its consultant, RiskCentrix, LLC. In addition, FEI filed with the Commission on a confidential basis the "Price Risk Management Plan Effective April, 2011 to October, 2014." This included the program objectives and the key elements of the 2011 PRMP which includes Programmatic, Defensive and Value hedging measures as well as a program of Basis Swaps designed to hedge price exposure at the Sumas trading hub. These filings collectively constitute the FEU response to the Commission Directives in Orders E-23-10 and E-24-10 respectively. On February 18, 2011, FEU filed redacted copies of both of these documents which were suitable for public review. On February 27, 2011, the Commission issued Order G-23-11 which concluded that prior to making a determination on the need for a hedging program, a review of the 2011 PRMP Objectives was required and established a regulatory process. In these Reasons for Decision, the Commission Panel will examine the evidentiary record and provide a determination on the validity of the PRMP Objectives and whether there is a need for a formal hedging program. For clarity purposes, the Commission Panel acknowledges its understanding that the Review Report applies to both Utilities while the PRMP applies to FEI only as stated in the cover letter.

1.2 The Applicant

FEI and FEVI are companies incorporated under the laws of the Province of British Columbia and are wholly owned subsidiaries of Fortis Inc. On March 1, 2011 the Terasen group of companies began operating under the FortisBC Energy Inc. brand name but continue to operate as separate legal entities. Fortis BC Energy and its affiliated companies sell and deliver natural gas to residential, commercial and industrial companies throughout British Columbia. They provide service to over 940,000 customers in 125 communities encompassing 95 percent of natural gas users within the province.

1.3 Key Stakeholders

The key stakeholders of the FortisBC Utilities Price Risk Management Program and related hedging strategies are its ratepayers who purchase gas. FEU states that the program has three primary objectives related to: maintaining competitiveness with other energy sources, reducing price volatility and reducing the risk of regional price disconnects. The position of the Utilities is that the achievement of these objectives is in the best interests of customers. (FEU Final Submissions, p. 5) Accordingly, the Commission Panel has the expectation that the benefits derived in satisfying these objectives must be sufficient to justify them in relation to additional ratepayer costs.

1.4 Orders Sought

As outlined in its Final Submissions FEU is seeking the following:

- The Commission's endorsement of the price risk management primary objectives which have been reviewed in light of developments including the introduction of the *Clean Energy Act* and increased domestic gas supply; and

- Approval of the FEI 2011-2014 Price Risk Management Plan dated January 27, 2011, which includes the implementation strategy and hedging instruments necessary to meet the objectives.

1.5 Regulatory Process

The review of the Filing was conducted by way of a written proceeding. The Interveners in this proceeding were the British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO) and the Commercial Energy Consumers Association of British Columbia (CEC). Both of these Intervener groups participated very actively in the processes. The Regulatory Timetable which included two rounds of Information Requests (IRs), Final Submissions from the participants and Reply Submissions from the Applicant is summarized in Appendix 1.

2.0 COMMISSION PANEL DECISION SUMMARY

The Commission Panel has reached the following conclusions regarding the FEI 2011-2014 Price Risk Management Plan and its objectives:

1. Endorsement of the FEU PRMP Primary Objectives

   - **The need for an objective related to the competitiveness of natural gas with other energy sources has not been established.**

   - **Moderation of the volatility of natural gas prices to stabilize customer rates is a reasonable goal for the Utilities to pursue. However, the Panel rejects the notion that it necessarily follows the proposed PRMP is the most cost-effective approach or solution.**

2. Approval of the FEI 2011-2014 PRMP

   - **With the exception of those elements related to the usage of Sumas-AECO Basis Swaps, we reject the FEI 2011-2014 PRMP dated January 27, 2011.**

3.0 BACKGROUND

3.1 Natural Gas Overview

FEU provided evidence that the natural gas market in North America has undergone significant changes in the last few years. There has been a dramatic increase in supply, largely from unconventional supply sources (coal bed methane, tight gas and shale gas). Supply increases have also been driven by advances in horizontal drilling technology that have reduced production costs. At the same time, demand for natural gas has been reduced in direct response to the downturn in the global economy. The bulk of this reduction is attributed to a drop in demand from industrial customers. The result has been record high gas storage levels and depressed natural gas prices.

FEU foresees that natural gas prices in the future could be quite different than today, as gas supply activity diminishes in response to low gas prices and industrial demand increases with economic recovery. These broad supply and demand factors are seen as longer term affecting natural gas prices over periods of years rather than months. (Exhibit B-1, pp. 16-21)

In the short term, FEU sees natural gas prices as potentially being affected by a number of factors including:

- Supply disruptions such as pipeline constraints during peak demand periods;
- Weather related supply disruptions such as hurricanes that disrupt production during the active hurricane season in the summer months;
- Unusually hot summer temperatures increase demand for natural gas for air conditioning loads;
- High demand for space heating in the winter months; and
- Relative prices of competing fuels, such as crude oil or coal. (Exhibit B-1, p.22)

In assessing the future impact of these supply/demand factors, FEU concludes that there is no information to suggest with any certainty that future market price volatility or market price spikes will be any greater or any less than in the past. (Exhibit B-5, CEC 1.13.2)

3.2 FEU Hedging Performance

3.2.1 Historical Impact of FEU Hedging on Price Volatility and Competitiveness with Electricity

FEU sets out a graph demonstrating that the FEU hedged commodity rate is less volatile than the AECO market (Exhibit B-4, BCOAPO 1.2.2). It also shows that the FEU hedged rate has generally tracked above the AECO market price, has been moderately higher than the "Electric Equivalent 60 percent Efficiency bench mark, and significantly lower than the "Electric Equivalent 90 percent Efficiency bench mark." FEU sees the Electric Efficiency bench mark as being significant for assessing the competitiveness of natural gas in applications such as water heating where natural gas water heaters are only 60 per cent efficient relative to electric water heaters, while the 90 per cent bench mark is significant with respect to natural gas's competitiveness with electricity for space heating purposes. (Exhibit B-1, p. 51-55)

3.2.2 Cost of FEU Hedging Programs

FEU presented information on the hedging losses for both FEI and FEVI. The results are summarized below in Tables 1 and 2.

TABLE 1

FortisBC Energy Inc.			
Year	Total Annual Hedging Gains/(Costs) ($ millions) (A)	Total Commodity Purchased ($ millions) (B)	Gain/(Cost) as a percentage of Total Commodity Purchased (A/B)
2000	$26.4	$574.5	4.60%
2001	$(56.3)	$763.7	(7.37%)
2002	$(123.9)	$626.9	(19.77%)
2003	$8.6	$721.8	1.19%
2004	$15.6	$675.8	2.3%
2005	$66.2	$773.5	8.56%
2006	$(88.1)	$758.0	(11.62%)
2007	$(136.8)	$804.5	(17.01%)
2008	$(40.9)	$825.7	(4.96)
2009	$(163.1)	$620.1	(26.29%)
2010	$(133.8)	$491.5	(27.23%)

- Total Commodity Purchased is based on the annual commodity costs including hedging gains/costs, net storage activity and commodity resale.
- Total Commodity Purchased includes Lower Mainland, Inland, and Columbia service areas.
- Figures are provided on a calendar year basis.

TABLE 2

Fortis BC Energy (Vancouver Island) Inc			
Year	Total Annual Hedging Gains/(Costs) ($millions) (A)	Total Commodity Purchased ($millions) (B)	Gain/(Cost) as a percentage of Total Commodity Purchased (A/B)
2000	n/a	$44.2	n/a
2001	n/a	$66.6	n/a
2002	$0.3	$49.2	0.57%
2003	$4.3	$70.9	6.09%
2004	$2.6	$71.9	3.66%
2004	$5.2	$94.3	5.49%
2006	$(5.0)	$93.0	(5.35%)
2007	$(6.3)	$92.3	(6.87%)
2008	$(1.8)	$103.1	(1.70%)
2009	$(19.7)	$82.0	(24.04%)
2010	$(15.1)	$67.9	(22.22%)

- Hedging activity for FEVI began in 2002.
- Total Commodity Purchased is based on the annual commodity costs including hedging gains/losses, net storage activity, and peaking gas resale.
- Figures are provided on a calendar year basis.

(Exhibit B-3, BCUC 1.1.1)

For the last five years FEI, on average, had hedging losses of $112.5 million per year and FEVI losses of $9.6 million. Losses for both utilities were most significant in the 2009-2010 periods which coincided with a sharp drop in natural gas commodity prices.

Reviewing each area of hedging activity based on the hedging cost and volume data supplied by FEU shows that FEU has effectively used Basis Swaps to lock in the AECO/Sumas basis spread to the benefit of its customers. The average cost of basis spreads for the period 2006 to 2010 was only $0.06/GJ. This is significantly less than the costs of other hedging instruments over this period which were $2.24/GJ for financial fixed instruments, $1.38/GJ for costless collars and $1.34/GJ for calls. The costs of each of these instruments are illustrated below:

TABLE 3

Average Gains (Costs)/GJ of Hedging Instruments for the Period 2006 to 2010

Year	Financial Fixed			Costless Collars		
	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)
2006	($75,059,847)	47,721,411	($1.57)	($24,952)	5,194,800	($0.005)
2007	($117,924,893)	49,813,300	($2.37)	($1,670,273)	2,310,750	($0.72)
2008	($22,607,026)	36,188,974	($0.62)	($955,268)	2,926,850	($0.33)
2009	($134,061,221)	38,326,914	($3.50)	(20,417,898)	7,936,637	($2.57)
2010	($124,842,095)	39,722,870	($3.14)	($10,524,415)	5,938,974	($1.77)
Total 2006-2010	**($474,495,082)**	**211,773,469**	**($2.24)**	**($33,592,806)**	**24,308,011**	**($1.38)**

Year	Basis Swaps			Calls		
	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)	Gains/Costs (A)	Hedged Volume (GJ) (B)	Average cost/GJ (A/B)
2006	$651,378	5,997,119	$0.11	($13,043,081)	11,104,300	($1.75)
2007	$1,608,145	8,032,774	$0.20	($20,023,329)	13,746,700	($1.46)
2008	($1,477,226)	7,780,700	($0.19)	($16,838,363)	13,165,500	($1.28)
2009	($2,664,092)	4,751,033	($0.56)	($7,710,476)	5,033,699	($1.53)
2010	($367,972)	13,412,949	($0.03)	($541,549)	388,514	($1.39)
Total 2006-2010	**($2,249,767)**	**39,974,575**	**($0.06)**	**($58,156,798)**	**43,438,713**	**($1.34)**

(Source: Exhibit B-4, BCOAPO 1.2.5)

3.3 Hedging Practices in Other Jurisdictions

FEU provides information on the use of hedging by gas utilities in other jurisdictions, including the nature and limitations of such use. Table 4 summarizes hedging activities in other jurisdictions.

TABLE 4

Hedging Activity in Other Jurisdictions			
Province	**Hedging Use**	**Max %of Options Approved for Use**	**Reference**
Alberta	Not Used	n/a	Exhibit B-5 p.37
Saskatchewan	In Use	70% summer and 90% winter subject to $15M in call option premiums (unlimited use of costless collars)	Exhibit B-3, p.48
Manitoba	Not used	n/a	Exhibit B-1, p.29
Ontario	Not used	n/a	Exhibit B-1, p.30
Quebec	In use	30% summer and 50% winter	Exhibit B-3, p.48

3.3.1 Provinces Allowing Hedging

Saskatchewan

SaskEnergy Incorporated (SaskEnergy) has an active hedging program that in FEU's view has enabled SaskEnergy to reduce market price volatility. It has allowed SaskEnergy to limit commodity rate changes to only twice a year for the past few years despite the price volatility in the marketplace. (Exhibit B-1, p. 29)

Based on conversations with SaskEnergy, FEU determined that:

- its hedging horizon is three to four years;
- it hedges a significant portion of its portfolio with a mix of instruments;
- it has the flexibility to choose the mix of hedging instruments it utilizes and generally prefers to use fixed price swaps in low price environments and more options in high price environments; and
- it is limited in terms of total budgeted costs for call options as set out in the Table 4 above.

FEU notes that the hedging approach including the use of the mix of hedging instruments is consistent with the FEU proposed enhanced hedging strategy. (Exhibit B-3, BCUC 1.9.1.2)

Quebec

Gaz Metro Limited Partnership (Gaz Metro) uses hedges to mitigate market price risk. FEU notes that, like the Utilities, Gaz Metro faces the challenge of competing with electricity. Because of Quebec's abundant hydro-electric generating capacity, electricity rates in the province are amongst the lowest in the country. FEU states that the hedging program of Gaz Metro helps in this regard. (Exhibit B-1, p. 30)

Based on conversations with Gaz Metro, FEU determined that Gaz Metro's approach to hedging is the same as SaskEnergy. Unlike SaskEnergy, Gaz Metro does not have any cost limitations in its use of options. (Exhibit B-3, BCUC 1.9.1.2)

Manitoba

Manitoba Hydro does not have a formal hedging program. For its default service offerings, it is allowed to offer fixed rate programs to its customers and does engage in hedging activity to support those offerings. As the utility is able to offer fixed rate services, Manitoba Hydro has been directed to wind down its hedging program related to the quarterly standard variable rate offerings by July 2011 and to cease any hedging for periods beyond this month. (Exhibit B-3, BCUC 1.9.1.2)

3.3.2 Provinces Not Allowing Hedging

Alberta

FEU notes that until this past winter, the government of Alberta provided natural gas customers with a rebate if natural gas prices exceeded $5.50/GJ. This effectively insulated consumers from price volatility whenever gas rates exceeded this threshold. However due to the impact of the recent recession on Alberta government revenues this program was discontinued. Currently with the absence of a rebate program and with no hedging programs by Alberta utilities, customers are fully exposed to market prices. Natural gas rates in Alberta are adjusted monthly. (Exhibit B-5, CEC 1.23.1)

Ontario

The primary natural gas utilities in Ontario, Union Gas Limited (Union Gas) and Enbridge Gas Distribution Inc. (Enbridge), had hedging programs in the past but do not currently. Their hedging programs were cancelled by the regulator, the Ontario Energy Board (OEB) in 2007 and 2008. While these utilities maintained that their risk management activities had provided a material reduction in rate volatility, the OEB disagreed and found that the quarterly rate adjustment and the equal billing plan provided sufficient rate smoothing effects. FEU strongly disagrees with this conclusion. (Exhibit B-1, p. 30)

FEU also points out that a major difference in circumstances between the Ontario utilities and the Utilities is that the Ontario utilities have significant amounts of contracted storage capacity (166 PJ). The Ontario utilities' access to the liquid Dawn market hub reduces their need to purchase seasonal and peaking gas and allows them to take advantage of favourably priced spot gas when load requirements dictate. In contrast FEU states that storage capacity in the Pacific Northwest is relatively scarce and FEU does not have the same access to storage resources as Ontario utilities. This is seen as having adverse price impacts in the Pacific Northwest region, particularly at Station 2 and Sumas during periods of high demand, typically seen during cold winter months. (Exhibit B-5, CEC 1.23.1)

To enhance storage and provide peaking services a number of activities have been undertaken by FEU. FEVI is currently completing the construction of the Mt. Hayes LNG storage facility on Vancouver Island, which will add 1.5 billion cubic fee (Bcf) of storage capacity to the area and provide peaking services to both FEVI and FEI beginning in 2011. In 2006, FEI contracted for a long-term capacity addition at Jackson Prairie in the Pacific Northwest, which helped to underpin the ongoing expansion of that facility. FEI also holds the largest amount of storage capacity at Mist, other than that held by Northwest Natural for its own customers. FEI in the past has investigated the potential for greenfield underground storage projects in the region, however, it has concluded that no cost effective opportunities are available outside of limited potential for further expansions at Mist or Jackson Prairie. (Exhibit B-8, CEC 2.6.1)

3.3.3 Comparative Assessment of Results in Other Jurisdictions

FEU has not undertaken a comparative quantitative performance analysis for utilities in other jurisdictions and is not privy to performance details where hedging is done. As pointed out by FEU, each utility faces unique operating and market environments and competitive challenges. This limits the usefulness of the assessment of the use (or non-use) of hedging activity in other jurisdictions as a determinant of the merits of FEU proceeding with its proposed program. (Exhibit B-5, CEC 1.23.2)

4.0 PRICE RISK MANAGEMENT - PROPOSED PROGRAM

4.1 Price Risk Management Plan Objectives

FEU states that the primary objectives of the PRMP can be described as follows:

(i) improve the likelihood that natural gas will continue to be competitive with other energy sources;

(ii) moderation of gas price volatility and its effect on customer rates; and

(iii) reduction of risk due to regional price disconnects.

FEU further states that the PRMP has a further underlying objective of providing this volatility protection and competitiveness at a reasonable cost to its customer base. The Commission Panel considers these objectives as a basis for the justification of having a Price Risk Management Plan. Accordingly, we believe that any decision to move forward with a PRMP will be a consequence of the determinations made on the validity of these objectives and whether the benefits derived from achieving them justify the costs to ratepayers. (Exhibit B-1, p. 31) In what follows we will review submissions with regard to each of these.

4.1.1 Competitiveness with Other Energy Sources

FEU submits that the maintenance of competitiveness with other energy sources allows it to grow its customer base and provide continued reasonable rates. The Utilities state that while the primary competitive challenge currently is electricity this objective will become increasingly important in the future as more options for energy sources such as air or ground source heat pumps become popular. Further, it states that the maintenance of competitiveness is not only good for FEU customers but is also in the best interests of those who consume electricity.

FEU's view is that if natural gas rates are considered to be uncompetitive with electricity, the consequence will be upward pressure on both natural gas and electricity delivery rates. This is based on the expectation that customer and load migration from natural gas to electricity will occur. FEU submits that this in turn results in the need for electricity distribution upgrades and the requirement for incremental power sources. The cost of these is considerably higher than what it describes as the embedded cost of supply which is dominated by Heritage generation resources with an embedded average residential rate of $0.065/kWh. It estimates these new electricity sources to be in the $0.12/kWh or higher range. Correspondingly, FEU states that delivery rates for its customers would increase reflecting the decrease of system throughput and the fact that much of the utility cost of service is fixed. To illustrate this point FEU cites the example of its competitive challenge with hot water heating where natural gas has a typically lower efficiency level than electricity (60 percent as opposed to 90 percent for electricity hot water heaters) and where customers incur the lower step 1 electricity rate. FEU notes that if FEI were to lose its entire current residential and commercial water heating load (presumably because of an electricity cost advantage), the result would be a 22 PJ decline and delivery rates could increase between 12 and 17 percent. Moreover, FEU estimates that if this migration were to occur it would result in an electricity rate increase in the 5 percent range. (Exhibit B-1, pp. 31-34)

FEU's view is that electricity rates have historically been based on utility-owned supply and infrastructure costs and not on market-based prices. Also they have not been affected by market price volatility and significant increases. However, FEU note that given the current situation, BC Hydro faces an era where costs and rates will increase as the company moves to achieve self-sufficiency and cleaner energy. While it is acknowledged that this could improve the Utility's ability to manage electricity competitiveness, numerous supply and demand factors affecting the market price of natural gas along with the potential for carbon tax increases will add to its challenge of maintaining competitiveness in the future. (Exhibit B-1, pp. 37-38)

FEU reports it has experienced customer migration to other energy sources and states that some of this may be due to gas price volatility. In taking this position, FEU cites the 2008 Residential End Use Study (REUS) which concludes that "the increase in the real price (nominal prices adjusted for inflation) of natural gas over the long-run is contributing to the decline in use rates". Further, the authors of the study note that price spikes could induce customers to turn natural gas heating systems off in favour of readily available alternative secondary heating sources.

FEU reports that information in the 2008 REUS indicates that on average 3 percent of FEI and 11 percent of FEVI customers have made a main space heating fuel change in the last five years with a net shift away from natural gas to electricity. The Utilities report that this is a unique occurrence as similar studies in 1993 and 2002 showed a positive gain for natural gas over electricity. Of the 3 percent of FEI customers who switched in the last five years, the study reports that 78 percent of these moved to electricity as their primary fuel source. As reported by FEU, the authors of the 2008 REUS state that increases in natural gas prices can cause fuel switching and based on this, the Utilities believe that natural gas prices have contributed to this migration. Further, based on these results, FEU asserts that natural gas hedging is of critical importance in mitigating market price volatility and its effects on natural gas rates. (Exhibit B-1, pp. 61-62)

In taking the position that a hedging program is critically important, FEU acknowledges that it is helpful only in dealing with competitiveness over the near term. As stated in the Filing "[a] narrowing of the gap between natural gas prices and electricity rates over the long run cannot be mitigated other than through a longer term hedging horizon. In other words, over the longer term it is the market that defines the competitive position of natural gas relative to electricity or other sources of energy." (Exhibit B-1, p. 5) FEU further acknowledges in response to BCUC 1.4.1.2 that because the hedging horizon extends out three years, its effectiveness is short term in nature and ultimately the natural gas marketplace and electricity rates will determine the competitiveness of natural gas over the long term. FEU also notes the impact of government policy and public perception towards energy and the role of natural gas on long term competitiveness.

With respect to the competitiveness objective, BCOAPO submits that its belief is that competitiveness of natural gas with other energy sources is in the ratepayer's interest. However, BCOAPO submits that this is best achieved through rigorous control of distribution and procurement at the utility level. (BCOAPO Final Submissions, p. 2) The CEC submits that a review of the competitiveness evidence is an indication of how the FEU has attempted to blend the management of short term price volatility with longer term competitiveness issues. The CEC states that FEU's treatment of competitiveness identifies the key comparative issues between gas and electricity as a heating source but fails in making a connection between competitiveness and price risk mitigation. After providing a lengthy list of examples taken from FEUs responses to IRs, the CEC concludes that the majority of the evidence does not provide support for the need for a price risk management objective designed to keep natural gas pricing competitive with electricity. (CEC Final Submissions, pp. 1-4)

In Reply, FEU states that the assertions of the BCOAPO and the CEC that the objective of maintaining competitiveness should not be part of the plan objectives is not based on the belief that competitiveness is an invalid objective. FEU states that the claim of the interveners is that the hedging strategy over the long run cannot mitigate the market forces which will ultimately determine natural gas and electricity rates which it views as an oversimplification. The Utilities argue that hedging can help with the near term maintenance of competitiveness for the three year hedging plan period. FEU further argues that "[m]arket price volatility can effect competitiveness in the near term as natural gas customers change their consumption behaviour or switch fuel sources based on the real or perceived view that natural gas is uncompetitive." FEU states that the CEC concedes this point in its submissions. In response to BCOAPO's assertions with respect to cost controls FEU notes that the Utilities do employ cost controls for distribution and operating expenses but they do not affect the cost of gas resources. Further, the Utilities state that procurement (Annual Contracting Plan) resources have limited ability to manage competitiveness and commodity rate volatility. (FEU Reply Submissions, pp. 2-3)

4.1.2 Moderation of the Impact on Rates from Gas Price Volatility

FEU believes that reducing rate volatility is a critical factor and improves the Utilities ability to compete with other forms of energy. With respect to rate volatility FEU asserts the following:

- Moderating market price volatility provides customer value.
- Customers have indicated that they desire a degree of rate stability.
- Customers accept this stability may come at reasonable cost.

To support its position FEU has cited a number of research studies which have been conducted to assess the importance of rate stability. (Exhibit B-1, p. 31)

i. Residential Customer Price Volatility Preferences Study

This study was conducted in February, 2005 by Western Opinion Research Inc. and was designed to survey customers concerning their tolerance for rate volatility. This study involved qualitative focus group research to identify the range of opinions on the subject and assist with preparing the questionnaire for the quantitative part of the study. Key findings included the following:

- Customers report that natural gas is one of the more significant monthly payments.
- Customers cannot afford large bill price increases.

The average customer tolerance for annual billing changes is $169 or 16 percent of the annual bill (with a range of 11 to 17 percent depending on the group they fit into).

Seventy percent of customers could tolerate bill changes of $100 or less.

With respect to this last point FEU interprets this to mean the tolerance of most customers is a maximum of $100 which is approximately 10 percent of an average yearly bill. In the study customers were provided with scenarios resulting from various approaches to natural gas price hedging. FEU reports that most customers surveyed were willing to participate less in downside rate movements if upside rate increases were correspondingly limited. These results were explained as indicating a concern with large bill increases as well as the impact of rate volatility on the ability to budget. (Exhibit B-1, pp. 63-64; Exhibit B-1, Appendix B)

ii. Residential Customer Focus Group

FEU reports that it recently conducted inquiries regarding preferences for rate stability in conjunction with a November 2010 focus group with customers enrolled in the Commodity Unbundling Program. Customers were given three rate scenarios (a fixed rate, a variable or market rate and a controlled rate with a tighter range than the variable rate) and asked to give their preferences. FEU reports that the majority favoured a controlled rate and were willing to accept less downside rate participation than the variable rate if upside increases were also limited. Customers stated preferences for rate stability and less bill surprises are reasons for the selection of this option. FEU submits that the results of this focus group provide validation in the current time period of the findings from the earlier 2005 study. (Exhibit B-1, p. 64-65)

iii. Customer Threshold for Gas Supply Volatility Study

In December 2004 Enbridge Gas Distribution (Enbridge) commissioned Ipsos-Reid to conduct a study designed to assess the customer's threshold for natural gas volatility. The study focused on residential and small commercial customers and assessed their sensitivity to rate volatility and risk management strategy preferences. Key findings of this study were as follows:

- Most customers place more importance on maintaining a steady rate than getting the lowest possible rate.
- Most customers wanted their utility to manage potential risk for large commodity price fluctuations.
- About half of the respondents expressed $100 as a tolerable fluctuation in their annual bill.
- Customers prefer rate stability to avoid large bill surprises and for budgeting purposes.

While acknowledging that this study was conducted in another jurisdiction, FEU notes that the results were not inconsistent with those in its jurisdiction and it appears that customers have a desire for a level of rate stability and avoid fluctuations in bills that can occur in the absence of volatility mitigation strategies. (Exhibit B-1, pp. 65-66)

BCOAPO's position is that a reduction in the volatility of gas market prices on behalf of ratepayers is a laudable goal but they should not be asked to bear the risk for this activity at any cost. The Intervener attributes significant reductions in gas commodity bill volatility solely to the existence of mechanisms such as gas cost deferral accounts and the practice of quarterly rate adjustments pointing out that to some degree the Utilities concur. BCOAPO notes that the information provided by the Utilities with respect to hedged versus unhedged rates in response to an information request include the impact of these two mechanisms. Additionally, it summarizes the impact of the program by stating that "it is not at all clear that the estimated historical reduction in volatility was worth the costs incurred." What is clear to the BCOAPO is that the approach has led to significant ratepayer cost increases citing gains in only four of the last eleven years totalling $116.8M and losses totalling $742.9M for the remaining seven years. Further, the Intervener points out that in spite of what it describes as a dismal hedging record, the FEU, in response to CEC IR 1.1.2, states that the primary PRMP objectives have been met at a reasonable cost over the last ten years. (BCOAPO Final Submissions, pp. 2-6)

The CEC submits that the evidence in the filing and IRs is supportive of the existence of natural gas price volatility. Further, the CEC states the evidence also supports the view that price volatility affects customer perception of short term competitiveness which in turn has an impact on the customer's decision-making process with respect to changing heating application fuel types. It saw no need to repeat the evidence to support these positions and submits that it is in strong support of the need for an objective to moderate the impact on rates from natural gas price volatility. (CEC Final Submissions, p. 4)

In Reply, FEU acknowledge the support of this objective from the CEC and state that the concerns raised by BCOAPO relate to questions as to whether what was achieved was worth the costs incurred rather than whether this is an important objective. The Utilities also comment upon the recent unprecedented market declines and their impact upon hedging costs and state this is not indicative of past hedging performance or that going forward. In FEU's view, the proposed hedging strategy which allows for greater use of options places it in a better position to cap high prices and also participate in any price declines. (FEU Reply Submissions, p. 3-4)

4.1.3 Reduction of Risks Due to Price Disconnects

FEU describes a period of disconnection occurring "when increased demand in the Pacific Northwest including British Columbia creates a lack of gas delivery capacity at Huntingdon causing Sumas prices to increase significantly and disproportionately above other regional hub prices such as Station 2 and Alberta prices." The Utilities maintain that the management of the Sumas price exposure becomes critical, especially during a price disconnection period and is believed to be an important objective of the hedging strategy. An example of price disconnection provided by FEU includes the winter of 2000/01 when natural gas prices peaked at $60.96/GJ and experienced unprecedented price volatility. More recently, in November 2010 during a particularly cold weather period, the Sumas price disconnected from the AECO and the Henry Hub price and spot prices which had traded below $4.00 US/MMBtu ran up to almost $5.50 US/MMBtu. FEU concludes that this latest example highlights the fact that even though the supply of natural gas in North America is abundant, price increases and volatility can occur when regional demand increases.

FEU has traditionally used Sumas-AECO Basis Swaps where the Sumas price exposure is converted to an AECO floating price plus a fixed Sumas-AECO price differential to remove the Sumas floating pricing risk in order to manage this risk within the commodity and midstream portfolios. FEU points to the fact that pipeline capacity has not kept up with demand growth in recent years. Accordingly, the Utilities believe there is greater potential for the Sumas basis to widen from AECO and Station 2 during periods of high demand than in the past. During such periods, the Sumas price will increase to draw gas away from Alberta and cover interruptible T-South transportation charges. The Utilities note that basis hedging serves primarily to protect against cold weather, high demand Sumas price disconnects. (Exhibit B-1, pp. 68-72)

BCOAPO offers no specific comments with regards to the objective related to regional price disconnects. The CEC views the issue of price disconnects as being a special case of price volatility and belongs under this objective rather than meriting a specific objective of its own. (CEC Final Submissions, p. 5)

FEU submits it is best as a separate objective as it is distinct from more general market price volatility and requires separate handling in terms of hedging strategy. In addition, keeping it separate distinguishes it as being unique to this region as are constraints effecting Sumas pricing and serves to highlight its importance in the management of customer risk.

4.2 Proposed Hedging Strategies

To assist in the review of the existing hedging program and objectives and provide recommendations for the future, FEI selected RiskCentrix an external consultant with much experience in the design and implementation of commodity risk mitigation programs for both gas and electricity utilities. The RiskCentrix review concluded that the FEI objectives for the PRMP were appropriate and consistent with those of other utilities as were the existing hedging program strategies. RiskCentrix then focused on ways to improve the existing hedging program to continue to achieve objectives with greater focus on cost effectiveness.

RiskCentrix recommended a hedging strategy with a number of key elements designed to achieve the objectives. Included in these are the following:

- programmatic hedging to reduce volatility on a scheduled basis;
- defensive hedging to respond to potential increases above specific price levels;
- value hedging to take advantage of favourable price opportunities; and
- Basis Swaps for Sumas price risk management.

The RiskCentrix recommendation is for a monitor-and -respond style of risk mitigation as opposed to one which is primarily programmatic. FEU states that this approach allows for mitigation of customer rate increases and reduces the potential for intolerable hedging costs. Key refinements to the existing hedging program recommended by RiskCentrix include a reduction in reliance on programmatic hedging, the setting of rules for defensive hedge responses, the addition of value screening criteria for incremental hedge accumulation and a greater reliance on call options. The FEU proposed hedging strategies are outlined below. (Exhibit B-1, pp. 84-85)

4.2.1 Programmatic Hedging

The RiskCentrix recommendation calls for 25 percent or less of both winter and summer volumes to be hedged programmatically. This is a significant departure from the past where FEI typically hedged 60 percent of winter and 45 percent of summer volumes programmatically. The programmatic hedges will be done with fixed price swaps in equal increments monthly based on a schedule which extends out 3 years. (Exhibit B-1, pp. 85, 89)

4.2.2 Defensive Hedging

Defensive hedging is used only on an as needed basis. It is only in those cases where potential price movements would have the effect of increasing costs above a predefined tolerance level that a defensive hedge would be initiated. FEU explains that the tolerance targets for defensive hedging will be integrated with predefined tiers based on customers' tolerable bill preferences and electric equivalent commodity component benchmarks. FEU will use tiers where the first defensive price target will be related to the maximum tolerable customer rate increase and other tiers related to predetermined electricity benchmarks. FEU notes that this strategy will be implemented with fixed price swaps and options. To allow for gradual ramping into a defensive posture, defensive hedges will be made within a two year window of the term being hedged. (Exhibit B-1, pp. 85-86, 90)

4.2.3 Value Hedging

As outlined by FEU, value hedging using fixed price swaps will be used to take advantage of favourable pricing opportunities and is similar to accelerated hedging the Utilities have used in the past. It is the RiskCentrix recommendation that screening data criteria based on the shape of the forward price curve be added and this type of hedging only be used when the forward price curve is in contango or where forward prices increase further out in time. FEU states that value hedging would be implemented only when a specific predefined price target was reached. They note that the rate at the beginning of this year of $4.568/GJ is the lowest commodity rate since inception of the Commodity Cost Reconciliation Account (CCRA) and that setting a target below $4.50/GJ would assist in maintaining low commodity rates and provide value for the customer. Noting that the FEU are competitively challenged for new or retrofit hot water heating customer's falling into the Step 1 rate, and assuming 50 percent of BC Hydro's rate increases are approved, the Utilities note the benchmark target is near $4.00/GJ to $4.50/GJ from 2011 to 2014. (Exhibit B-1, pp. 87, 91)

4.2.4 Basis Swaps

The need for Basis Swaps to manage winter Sumas price exposure was discussed previously in Section 4.1.3. FEU reports that that this program will continue to be consistent with past practice. (Exhibit B-1, p. 91)

BCOAPO notes its understanding that the hedging proposal before the Commission does not suggest that FEU will continue with historical practices. In spite of this, the position of BCOAPO is the Commission Panel should reject what the Utilities "believe to be 'reasonable costs' associated with hedging activities in whatever form" and, presumably, the filing itself. BCOAPO notes that it does not find compelling evidence to support the view that the hedging strategy being proposed will come at any lower cost to ratepayers. On the contrary, it notes that the possibility for highly volatile costs and impacts exists if FEU is to embark on their proposal as filed. BCOAPO submits that there is a lack of evidence on the record suggesting that the proposed strategy has been tested in practice and concludes the PRMP is therefore inordinately risky to ratepayers. (BCOAPO Final Submissions, pp. 6-7)

The CEC submits that FEU has made credible enhancements to their hedging programs and there is likelihood for improvement in performance in the 25 to 30 percent range. Nonetheless, the CEC asserts that the PRMP will provide only a modest level of price risk management at significant cost to its customers. However, the CEC 's position is price hedging programs should be a matter of choice for the customer and offered as one of a number of alternatives for price risk management to FEU's customer base. CEC suggests it would be helpful in aiding with customer retention. (CEC Final Submissions, p. 18)

FEU in its Reply takes exception to the position of BCOAPO and the arguments raised that challenge whether the hedging is able to achieve the objectives. Specifically, FEU respond to assertions regarding evidence supporting whether the strategy has been tested in practice, the possibility of volatile costs and high risk to ratepayers, the methodology for deploying defensive hedging, the impact of a greater use of options, the accuracy of statements related to trying to "time or beat the market" and the lack of discussion or analysis regarding probable outcomes of the strategy and impact on the reduction of bill volatility. (FEU Reply Submissions, pp. 7-10)

With respect to the CEC's submission that customers be given the choice to select a hedging program as one of a number of options, the FEU responds that there are a number of key reasons why hedging should continue on behalf of customers:

- A variable rate option with no hedging exposes customers to greater rate volatility than they are used to or willing to tolerate.
- The use of a price stability rate rider (as discussed in Section 4.4.1) may not prove to be significantly different than using deferral account balances and in the event balances become high, may come with similar risks or cost. Moreover, such a vehicle would have no effect on the underlying market prices effecting gas costs and thus be limited in mitigating rate volatility.

- Either option would require significant expenditures for development and execution of the separate service which would be recovered from ratepayers. (FEU Reply, pp. 12-13)

4.3 Existing Rate Stabilization Tools

This Section provides an overview of the other tools and/or mechanisms that FEU currently uses to stabilize customer rates by reducing the impact of volatility in gas commodity markets. In addition, the position of the Company as well as the views of the Interveners regarding these mechanisms is summarized.

4.3.1 Overview of the Existing Mechanisms

Gas Cost Deferral Accounts

Gas cost deferral mechanisms essentially collect the difference between forecast and incurred gas costs with the balances to be recovered from customers or refunded to customers at a later date through rates. This way deferral accounts allow some rate stability by deferring the impact of commodity market volatility on gas costs. Two deferral accounts are used to stabilize rates.

The Commodity Cost Reconciliation Account became effective April 1, 2004. Since that time deferral account balances, on a net of tax basis, have generally been within a ± $50 million range.

The Midstream Cost Reconciliation Account (MCRA) contains the midstream costs which comprise a mixture of costs which are fixed in nature (related to storage and transportation demand charges) and those which are variable in nature (related to storage injections and withdrawals as well as seasonal commodity purchases and sales). (Exhibit B-1, pp. 75-76)

Quarterly Rate Adjustment Mechanism

Currently FEI reviews the CCRA rate on a quarterly basis and, as a rule, uses a CCRA rate adjustment mechanism with a 95 percent to 105 percent under/over recovery dead band on the rate change trigger ratio in determining whether or not a rate adjustment is required. The midstream cost recovery rates or MCRA rates are also reviewed quarterly as part of the FEI quarterly gas cost reports filed with the Commission. However, under normal circumstances, the MCRA rates are typically reset annually. (Exhibit B-1, p. 76)

Use of Storage

The effective use of storage is another tool used by FEU to manage price volatility and gas cost in order to enhance price stability. Storage provides both operational and financial benefits and enables FEU to achieve the Annual Contracting Plan (ACP) objective of balancing supply reliability, portfolio diversity and cost minimization. (Exhibit B-1, p. 78) Specifically, storage with associated transportation service provides a physical or “natural hedge” by realizing and locking in the differential between summer and winter prices. The underlying intent is to inject gas in the summer months when gas prices are generally lower for withdrawal in the colder winter months when prices tend to be higher. (FEU Final Submission, p.21).

Equal Payment Plan

The Equal Payment Plan (EPP) provides customers with equal monthly bill payments for a twelve month period, based on their previous year’s consumption volumes. The monthly EPP instalments are automatically reviewed every three months during the plan, and are adjusted if necessary to reflect significant changes in usage or rates. Approximately 31 percent of FEU customers are signed up for this billing option. (Exhibit B-1, p. 66)

Commodity Unbundling – Customer Choice

Both residential and commercial customers can also enrol in the Commodity Unbundling Program to ensure rate stability. In this program, called Customer Choice, customers can purchase their natural gas from marketers at a fixed rate for one to five year terms instead of purchasing their commodity supply from FEI at its quarterly adjusted rate. Currently, approximately 16 percent of residential and commercial customers are enrolled with a marketer. (Exhibit B-1, Review Report, p.67)

4.3.2 FEU Submissions

FEU submits that it uses the above mechanisms to complement hedging in moderating rate impacts and maintaining competitive rates for natural gas customers. It further submits that "while all of these mechanisms help to some degree in achieving the objectives, they cannot individually or collectively replace the value of cost effective hedging in fully meeting the objectives." (FEU Final Submission, p. 19) The following explanations provided either in the Review Report or in FEU responses to IRs, are put forward to support the Utilities' position:

FEU on Deferral Accounts

Deferral accounts do not affect or help manage the underlying commodity prices embedded in the cost of gas, which will eventually flow through to customers. The hedging program, on the other hand, does impact the underlying commodity prices and so directly manages gas costs. (Exhibit B-3, BCUC 1.8.3)

Generally deferrals do not serve as an alternative to an effective hedging program. A short-duration deferral mechanism adds modest additional stability when used in conjunction with a robust hedge program; it is inferior as a stand-alone approach in the absence of a hedge program. Furthermore, the risk of deferral accounting is that deferrals could accumulate to unsustainable levels resulting in the need to ultimately pass through more radical costs. (Exhibit B-1, Appendix A of the Review Report, p. 24)

FEU on the Equal Payment Plan

Under the EPP consumers will ultimately have to pay the rate impacts of any market price fluctuations as each customers' account is trued up to the actual usage and rates at the end of the twelve months. Indeed, during periods of extremely volatile market prices EPP customers may also be subject to quarterly rate changes. The hedging program, unlike the deferral accounts and EPP, directly mitigates market price volatility by affecting the underlying commodity cost of gas. (FEU Final Submission, p. 21)

FEU on the Use of Storage

Despite the benefits provided by storage it is not a substitute for hedging for the following reasons:

(i) The amount of storage that can physically be contracted is primarily limited by the availability of third party storage capacity and the associated pipeline transmission capacity for delivery to the service areas during the winter months. (Exhibit B-7, BCOAPO 2.18.1)

(ii) Contracting for storage capacity increases associated storage and transportation fixed demand charges. Furthermore, because storage balances are usually drawn down at the end of each winter, the price protection associated with storage capacity is generally limited to a single season. With an effective hedging program, price protection can be provided for several years out in time. (Exhibit B-1, Review report, p. 85, FEU Final submission, p. 22)

(iii) Storage injections during the summer could be impacted by any adverse market price movements, such as price increases resulting from production disruptions caused by seasonal hurricanes.

In conclusion, while the use of storage does play an important role in managing the impacts of market prices on gas costs, it must be balanced with the hedging strategy and use of deferral balances in combination with the appropriate amount of index-based supply. (Exhibit B-8, CEC 2.8.1, FEU Final Submission, p. 22)

4.3.3 Intervener Submissions

BCOAPO

BCOAPO submits that "there is an insufficient basis that would allow parties, and the regulator, to conclude that approval of this Filing is warranted and we urge the BCUC reject the Utilities' Price Risk Management Plan on the grounds that (i) the regulatory onus on the utilities has not been met and (ii) approval could expose ratepayers to high costs with low benefits." (BCOAPO Final Submission, p. 9)

BCOAPO notes that there are significant reductions in gas commodity related bill volatility due solely to the existence of gas cost deferral accounts and the quarterly rate adjustment mechanism. Specifically, BCOAPO states the evidence has not established that the estimated historical reduction was worth the costs incurred. Furthermore, it submits FEU was unable to separately quantify reduction in volatility due to hedging vs. other mechanisms used. (Exhibit B-4, BCOAPO 1.2.1, 1.2.2)

Finally, BCOAPO does not consider the net hedging costs over the 2000-2010 period reasonable and submits there is no compelling evidence on the record that the proposed hedging strategy will come at any lower cost to ratepayers, nor that it has actually been tested in practice. (Exhibit B-3, BCUC 1.1.1, BCOAPO Final Submission, p. 6)

In reply, FEU submits the evidence on deferral accounts is that "these mechanisms do not provide the same degree of volatility reduction as hedging." Furthermore, FEU submits that "deferral accounts do not impact the underlying market prices and have limitations with respect to impacting short-term borrowing capacity." (FEU Reply Submission, p. 12)

CEC

The CEC submits that it sees the existing alternatives for price risk management as providing some interesting options for customers. The base quarterly price adjustments and deferral accounts seem to smooth out much of the price volatility but leave the question of how to handle the significant peak prices that come along from time to time. The CEC tends to agree with FEU's position that quarterly pricing and deferral account mechanisms are complementary to other price risk management.

The CEC also agrees with FEU that the EPP is essentially an additional complementary option for customers. Finally, the CEC submits that gas marketer contracts with price certainty provide an option for customers and that FEU should continue to offer this option. (CEC Final submission, pp. 12-16)

4.4 Other Options for Rate Stabilization

To assess the benefits of hedging as compared to other utility alternatives to stabilizing natural gas prices and their impact on customer bills, other options should be explored as well. The CEC provided some suggestions which are addressed below.

4.4.1 Customer Price Stability Fund

The CEC submits the evidence demonstrates that FEU customers would be substantially better off with a self-hedging Price Stability Fund. At a minimum, the CEC states customers might prefer the choice between a self-hedging price risk management option and a market risk management option. In terms of numerical verification, the CEC points out that had FEU adopted a policy of offering a price stability rate rider to customers of 5.25 percent of the commodity purchased over the eleven years of performance data provided, the fund would have generated approximately $400 million over that time period. If that amount had been applied to reduce the unhedged price peaks experienced over the period, the CEC submits, FEU customers would have enjoyed far greater price stability than what was achieved by hedging. Indeed, the $400 million would have been enough to produce essentially flat rates throughout the eleven year period. (Exhibit B-3, BCUC 1.1.1.1, CEC Final Submission, p. 15)

This contrasts to the hedging programs offered which cost customers some $626 million over the eleven years. The CEC submits that the hedging program achieved only very modest amounts of rate smoothing for the peaks, amounting to less than 33 percent of a full flattening of the rate peaks. (Exhibit B-3, BCUC 1.1.1.1, Exhibit B-4, BCOAPO 1.2.2) In conclusion, the CEC submits that the FEU needs to look much more closely at customer self-hedging as a price risk management tool. (CEC Final Submission, p. 15)

4.4.2 Customer Market Supply

The CEC notes that some customers would see the benefit of not paying the premium for hedging and submits that FEU is not currently making this option available. The CEC further submits that it would be highly relevant to customers to have the option for an 8.2 percent lower commodity cost without the hedging. (Exhibit B-1, Appendix B, p.4, CEC Final Submission, pp. 15-16) This would in effect provide the customer with the choice as to subscribing to the program.

4.4.3 Alternative Equal Payment Plans

As noted previously, the CEC agrees with FEU that the EPP is essentially an additional complementary option for customers to choose from for bill management. The CEC submits that FEU might find it useful to offer alternative EPP types, which provide more or less price stability at defined prices. (CEC Final Submission, p. 14)

4.4.4 Customer Choice for Price Risk Management

After reviewing the proposed price risk management enhancements proposed by the FEU the CEC acknowledges that the proposed enhancements may produce 25 percent to 30 percent improvement in the hedging program performance. However, the CEC still submits that the hedging program will only provide a modest level of price risk management for a significant cost to customers. Accordingly, the CEC further submits that "FEU should be permitted to provide an enhanced hedging option for consideration by customers and that it should be offered to customers to allow them to decide if the cost risk trade-off suits them."

In conclusion, the CEC submits that a hedged price option, a self-hedging option and no hedging option would represent an ideal suite of price risk management options to add to the existing mix. A customer choice of this nature would then allow the customers to decide the most reasonable trade-off to suit their personal circumstance. (CEC Final Submission, p. 18)

5.0 COMMISSION PANEL DECISION

5.1 Validity of Objectives

In Section 4.1, FEU outlined three objectives which were the basis for the PRMP. The proposed objectives involve maintaining the competitiveness of natural gas with other energy sources, moderation of the impact of gas price volatility and reducing risks related to price disconnects. The view of the Commission Panel is that these objectives can be separated into two categories; the need for competitiveness and the need to moderate natural gas price volatility as a means of stabilizing customer rates. These bear examination from the perspective of the FEU ratepayers who purchase gas as this group has been identified as the key stakeholder for these proceedings. We believe this will serve to assist in underlining the fact there are fundamental differences between the two and how they impact the gas purchasing ratepayer.

5.1.1 Need for Competitiveness

The Commission Panel finds that the need for an objective related to the competitiveness of natural gas with other energy sources has not been established.

The need for competitiveness speaks to the FEU position that it is in the customer's best interest that natural gas prices continue to be competitive with other energy options, principally electricity. FEU has outlined a scenario where there will be customer migration from natural gas to electricity if the competitive picture were to shift in favour of electricity. This in turn will lead to increased delivery rates and possibly result in an increase in electricity rates depending upon the reasons behind the change and the magnitude of customer migration. An interpretation of this is the customer is expected to fund the cost of a hedging program to mitigate what can best be described as a competitive business risk rather than a price risk with the ultimate effect being a stabilization of delivery costs. The Commission Panel is of the view that a Return on Investment (ROE) Hearing is a more appropriate forum for evaluating business risks and notes that in the most recent proceeding, FEU received a substantial increase in the level of ROE to compensate for increased business risk. The question arises as to why then is the gas customer being expected to bear the cost of the risks for which FEU is already compensated for within its approved rate of return. The Panel's answer is they should not.

Perhaps the more important consideration lies in the concept of competitiveness itself. The Commission Panel views the commodity price as just one of many elements affected by market forces which in concert determine the competitive position of natural gas relative to electricity and other energy sources. In addition, the Utilities must consider factors related to delivery costs as well as those affecting the cost of electricity itself. Considering only the commodity price and ignoring the potential for responding to competitive threats more broadly is in our view an inadequate response. This is especially important given FEU's admission outlined in Section 4.1.1 that well run hedging programs assist in dealing with competitiveness in the near term hedging horizon only. The Panel notes that a hedging program does not really deal with the issue of competition and the variability of the market but merely puts off the inevitable. A further consideration is that while an elimination of the gap between electricity and natural gas rates may occur over the long term, there is little to indicate this will occur over the nearer term covered by the hedging horizon.

The lack of rigorous analysis examining the hedging option against other options to mitigate competitive risk is also a concern to the Panel. This matter was queried in BCUC IR 1.2.1 where FEU was asked to "provide a detailed analysis on the risk issue, criteria that addresses the issue, the various alternatives, the pros and cons of the alternatives and the reasoning for the preferred alternative that best mitigates the risk." BCOAPO comments that this question was an opportunity to present the PRMP in a way "...that could demonstrate the appropriateness of the Proposal in terms of delivering ratepayer value for hedging dollars." BCOAPO further comments that FEU failed to seize this opportunity, a sentiment with which the Panel agrees. (BCOAPO Final Submission, p. 8) A comprehensive review such as that requested would have resulted in a more robust discussion of the competitiveness risk and outlined a broader range of alternatives.

Further, in determining the merits of an objective related to the competition with electricity, the Commission Panel believes it appropriate to consider the British Columbia's Energy Objectives as set out in the *CEA*, specifically objective (h) which is "to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia." (*CEA*, Part 1, 2(h)) It should be noted that the *CEA* objective (c) contemplates that at least 93 percent of the electricity in British Columbia be generated from clean or renewable resources. In this proceeding FEU has asserted that the PRMP can, in the short term, mitigate the impact of government policies that impact the competitiveness of natural gas to other energy forms or shape public perception that reduces the demand for natural gas. (Exhibit B-3, BCUC 1.11.1.1) The Panel's position is that it is not in the public interest to have a PRMP objective designed to mitigate the impact of an objective of government policy.

In summary, the Commission Panel bases its finding that the objective related to competitiveness of natural gas with other energy sources (principally electricity) is inappropriate for the following reasons:

- issues related to business risk have complexities beyond those of natural gas commodity cost and are more appropriately dealt with in the context of a ROE Hearing;
- in the long run the demand for gas versus electricity will not be driven by a PRMP but will be driven by market forces;

- in the current market environment short run competitiveness with electricity is seen to be largely driven by events of limited duration that cause market volatility, making this objective indistinguishable from the moderating of price volatility objective; and
- promoting gas use over electricity consumption where electricity use may better meet government policy objectives is inappropriate.

5.1.2 Need to Moderate Natural Gas Price Volatility

FEU's position is that there is a need for an objective to moderate natural gas price volatility as a means of stabilizing customer rates. In addition, FEU has asserted that there is also a need for an objective to reduce the risk of regional price disconnects with specific reference to Sumas-AECO disconnects. The Commission Panel, while acknowledging that Sumas-AECO disconnects are a unique circumstance requiring different tactics, agrees with the CEC that this is a volatility-related issue and sees no benefit in separating the two. Accordingly, the Panel will consider the risk of regional price disconnects as being addressed within the discussion of the need to control price volatility in order to stabilize customer rates.

The Commission Panel finds that moderating the volatility of natural gas prices is a reasonable goal for the Utilities to pursue. **However, the Panel rejects the notion that it necessarily follows that the proposed PRMP is the most cost effective approach or solution.**

As noted previously in Section 4.1.2, neither BCOAPO nor the CEC take issue with the need to take steps to moderate price volatility. The CEC has further pointed out the link between customer perception of short term competitiveness and its impact on the customer decision-making process as to the choice or change of heating fuel. In addition, various studies cited by FEU generally support the view that there is a decided customer preference for rate stability and there are limits to the size of annual bill changes customers indicate they are willing to accept. However, in the Commission Panel's view the key issue is not whether controlling volatility is a desirable outcome but how this outcome can be best achieved in a cost effective manner. In the following sections, 5.2 and 5.3 the Panel will address whether there is a need for a formal PRMP before examining some of the existing tools and potential for new alternatives to manage this volatility.

5.2 Need for a Formal Price Risk Management Plan

In the previous Section 5.1 the Commission Panel provided its assessment of the validity of the three PRMP objectives and found that the issue is really about volatility. In making this determination and rejecting the FEU's position that there is a need to be competitive with other energy sources (principally electricity) the question arises as to whether sufficient justification remains to support the need for a PRMP as proposed. While acknowledging that managing volatility is in the best interests of ratepayers, the Commission Panel is not persuaded that the PRMP as proposed is a requirement or even the most cost effective solution to the problem. **Accordingly, with the exception noted below, the Panel rejects the FEI 2011-2014 PRMP dated January 27, 2011.**

As outlined in Table 1 in Section 3.2, over an 11 year period commencing in 2000, FEI has experienced hedging costs which total $626.1 million. Based on a total commodity cost of $7.636 billion (inclusive of hedging costs or gains) what this means is that over this 11 year period FEI ratepayers have paid a premium to the market natural gas rate of 8.9 percent. It is understood that the two worst performance years in 2009 and 2010 were anomalies where natural gas prices dropped at an unprecedented rate and the FEI program experienced costs of $296.9 million resulting in a ratepayer premium of over 36 percent. However, relying upon the FEU response to BCUC IR 1.1.1, the Panel notes that the costs for the three preceding years (2006-2008) totalled $265.8 million. This converts to a ratepayers natural gas rate premium of 12.5 percent which is also well above the 11 year average. In spite of these snapshots over the last 2, 5 and 11 year periods FEU states that "[o]n average over the past decade, the direct hedging costs have been modest in light of the benefits of reduced market price volatility and maintaining competitiveness for customers." (FEU Final Submissions, p. 13) The Commission Panel does not consider these costs to be modest nor are we persuaded that the benefits justify these costs. On the contrary, the Panel considers forcing customers to pay a premium of 8.9 percent on average over the last decade as being a very high cost for marginal benefits. Add to this the fact that over the last five years customer premiums have consistently exceeded this level and the results of this program from the perspective of 'reasonable cost' in the Panel's view, can best be described as dismal.

FEU enlisted an outside consultant, RiskCentrix which has been instrumental in assisting the Utilities in making significant changes to the proposed program strategies. The Commission Panel acknowledges this and accepts the position that on a go-forward basis the results of the PRMP would potentially be more responsive to market changes. However, the Panel notes that improved responsiveness over the current program sets a low baseline and there is no data or analysis presented to suggest that hedging will effectively balance risk and cost objectives. As outlined in 5.1.1, we also note the lack of analysis examining the hedging option against a range of other alternatives. As a result, the Panel remains unconvinced the need for the PRMP has been adequately established.

FEU states throughout its evidence that the measure of this type of program is not gains or losses but whether the objective is achieved at a reasonable cost. Further, FEU uses the analogy of homeowner insurance which is used to protect against uncertain events and has equated this to hedging programs. The Panel views this analogy as a reasonable characterization, which in these circumstances, is useful. However, we would like to point out there is at least one major difference between the two situations. That is the customer purchasing home insurance has various coverage options including whether a policy will be purchased. With the proposed PRMP there are no customer driven options or the ability to opt out. Given the past performance of this program and the potentially high impact on ratepayer bills, the Commission Panel is in agreement with the submissions of CEC regarding the need for choice (CEC Final Submissions, p. 11) and finds that, at the very least, the decision to be involved with a hedging program, should be a choice made by the individual customer.

The Panel does accept that there are ongoing issues with price disconnects leading to pricing volatility which are most appropriately dealt with by the current practice of Sumas-AECO Basis Swaps. As pointed out previously, the Ontario jurisdiction which no longer has a hedging program does have access to substantial storage which could be used to mitigate these types of problems. This is not the case in British Columbia where the amount of and accessibility to storage is limited and other options to control such price disconnects must be pursued. The Sumas-AECO Basis Swaps program has proved to be a relatively low risk, low cost strategy which, as outlined in Table 17 of the Filing, has proved successful over time. **Accordingly, the Panel approves those elements of the PRMP related to the usage of Sumas-AECO Basis Swaps.**

In rejecting the full PRMP, the Commission Panel does not dismiss the view that there is a need for additional measures to control volatility. In Section 5.3 which follows we will discuss some of the existing means to manage volatility as well as explore some of the other alternatives which have been raised in these proceedings.

5.3 Alternatives for Rate Stabilization

When determining whether to endorse the price risk management primary objectives and whether to approve the 2011-2014 Price Risk Management Plan, the Commission Panel also considered how the proposed hedging program compares to other alternatives available for FEU to stabilize natural gas prices and customer bills. Section 4.3 provided an overview of the existing rate stabilization tools while Section 4.4 addressed other potential options for rate stabilization. In rejecting the PRMP, the Panel gave significant weight to reasonable cost. Specifically, the past costly hedging performance and prospects of on-going high ratepayer bill impact and found that given the existing other mechanisms and the availability of other potential options, a mandatory hedging program is not in the public interest. In this Section the Panel explains its views regarding the other available rate stabilization mechanisms and the role they play in managing natural gas price volatility.

FEU outlined a multitude of factors that can adversely affect gas prices and volatility in the short term, for periods of several months or longer. Examples of those factors included supply disruptions such as pipeline constraints during peak demand periods, weather related supply disruptions such as hurricanes, and unusually hot summer temperatures. **The Commission Panel finds that these short term incidents can be managed by the existing alternative mechanisms in conjunction with the use of Sumas-AECO Basis Swaps.**

5.3.1 Existing Rate Stabilization Tools

As noted previously, a number of rate stabilization tools are currently in use. These include gas cost deferral accounts, equal payment plans and the Customer Choice program. The purpose of these measures is to stabilize rates by reducing the number and frequency of price changes and thereby reduce volatility. These measures are addressed below:

Gas Cost Deferral Accounts

To assess the effectiveness of the existing programs in controlling price volatility the Panel first reviewed the Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance which were established in 2001 by Commission Letter L-5-01. Attributes of Deferral Account and Gas Cost Rate Setting Methodologies included in the Guidelines provide a framework for analyzing these tools and are reproduced in Appendix B. The key attributes are as follows:

- Rate Stability
- Price Transparency
- Size of Deferral Account
- Efficiency of Process

As noted previously, the deferral account balances since 2004 have generally been within a ± $50 million range and there is general agreement among the participants that the program has been successful in moderating rate impacts in the short term. This point was further supported by the Report on the CCRA and MCRA Deferral Accounts and Rate Setting Mechanisms submitted to the Commission by FEU on March 10, 2011. Based on that report, by Letter L-40-11 the Commission approved further enhancements to the 2001 Guidelines designed to reduce the need for small CCRA rate changes and moderate the growth of MCRA deferral account balances which are addressed annually. **Considering the criteria established in the 2001 Guidelines, the FEU evidence and Intervener submissions, the Commission Panel finds that the existing rate stabilization tools and mechanisms, enhanced as described above, continue to serve the intended purpose.** Furthermore, the deferral account balances seem to remain in a reasonable range, which means that the credit and liquidity risks are being managed. In supporting the continued use of these tools the Panel acknowledges that while deferral accounts provide some smoothing, they do not affect or help manage the underlying commodity prices.

Equal Payment Plan

The Equal Payment Plan is designed to level out payments over a year based on consumption levels in the previous year. The Commission Panel notes that 31 percent of FEU customers have chosen this option which indicates there is a desire among certain customers to have a steady rate throughout the year and to control volatility. While recognizing that this tool has no impact on the cost which will ultimately be paid by the customer, the Panel is persuaded this is a useful tool as it allows the ratepayer the option of stabilizing prices and allowing the impact of price volatility to be dealt with over a longer time period.

Commodity Unbundling – Customer Choice

The evidence that some 16 percent of residential and commercial customers are enrolled with a gas marketer demonstrates the existence of a group of customers preferring choice who are comfortable committing to a multi-year fixed price contract which guarantees commodity price stability. The Commission Panel notes that this program provides the ultimate in stability and protection against significant upward price movement. However, it offers no participation in the event that prices drop significantly as they have in recent years. Because of this, we are of the view that this program is a good fit for the group of customers who require price stability only but is less attractive to those who prefer to pay market price or at least participate in downward price movement when it occurs.

The Commission Panel believes each of the existing price stabilization mechanisms has a role to play both currently and in the future. However, we acknowledge that other than the Customer Choice commodity unbundling program, the existing mechanisms may not be effective in dealing with longer periods of considerable price volatility should they occur in the future. Therefore, FEU should continue to explore other alternatives; in particular, alternatives that would enable it to manage potential longer periods of persisting price volatility.

The Commission Panel believes the main reason for a utility not to hedge is the likelihood that the price-protection benefits from hedging will not justify the inherent costs. This is particularly the case during periods when relatively stable prices are expected. As discussed in Section 3.1, the natural gas industry has seen a dramatic turnaround in prices since 2008, and there are projections that shale gas may be able to supply the North American gas market adequately for decades at reasonable, more stable prices. More than ever, the Panel finds that in this new world the expected future value of hedging may be diminishing and benefits offered by other mechanisms can outweigh hedging. Under these circumstances, the Commission Panel believes that it is of utmost importance to provide customers a choice when it comes to rate stability and the price they are willing to pay for it.

For the reasons discussed above, the Commission Panel has rejected the FEI 2011-2014 Price Risk Management Plan. Should FEU, after reviewing the Decision, still believe that further steps to manage market gas price volatility and rate stability are required, the Panel urges FEU to explore new alternatives. In this regard, the Commission Panel wishes to emphasize the importance of choice as a principle. The Panel acknowledges the FEU reply submissions regarding the CEC proposals, especially the cost concerns. The Panel also notes that these proposals are largely untested and would require further analysis of the underlying assumptions.

Nonetheless, the Panel suggests FEU consider the CEC proposals among others. First, FEU is encouraged to consider the potential of offering an optional Customer Price Stability Fund. As described in Section 4.4, by way of a rate rider as a percentage of gas commodity purchased, customers would in effect be self-hedging and providing more stability. Second, FEU should consider offering an enhanced hedging program for customers, on an optional basis, along the lines recommended in the filing. After reviewing cost and risk trade-offs, customers can then determine whether insurance in the form of hedging would suit their personal circumstances. In other words, a customer can decide whether the cost of hedging is an appropriate premium for "peace of mind." In an optional hedging program, the Panel would expect the participants to cover the full cost burden. If FEU finds that alternative options such as these are warranted in the future, the Commission Panel invites FEU to submit a new filing for Commission's consideration.

5.4 Commission Panel – Concluding Remarks

The Commission Panel would like to add a few concluding remarks. Firstly, we do not want to leave the impression that there is only limited concern for ongoing rate stability and the impact of potential future volatility. With the current price of gas at levels which have not been seen in years, the Panel acknowledges that the potential for downward movement of the price of natural gas is limited and the potential for upward movement is greater. However, we also note that in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years. This is not to say that the risk of more dramatic increases in natural gas prices has been eliminated. On the contrary, factors such as the potential for growth in LNG exports and the possibility of a more dramatic economic recovery leading to increased consumption are just two of the myriad of events which could affect future natural gas prices. However, the Commission Panel's position is that hedging is not the way to deal with the potential for price increases. The key is managing volatility not price which is a result of market forces. The Panel has no desire to "close the door" on the consideration of all future hedging options. Given a change in external conditions, we would consider proposals on behalf of ratepayers to help in mitigating the relevant risks. However, we would like to be clear that the need for a formal hedging program as proposed has not been established by this Filing and given the performance of the PRMP over the last 10 years, a regular ongoing program applying to all ratepayers is not in the public interest.

REGULATORY PROCESS

**Terasen Gas Inc. (TGI) and Terasen Gas (Vancouver Island) Inc. (TGVI)
(collectively Terasen Gas)**

An Application for Approval of the Price risk Management Plan
Effective April 2011–October 2014

REGULATORY TIMETABLE

ACTION	DATES (2011)
Intervener and Interested Party Registration	Friday, March 4
Commission Information Request No. 1	Friday, March 11
Intervener Information Request No. 1	Wednesday, March 16
Participant Assistance/Cost Award Budgets	Friday, March 18
TGI Response to Commission and Intervener Information Request No. 1	Friday, March 25
Commission Information Request No. 2	Friday, April 1
Intervener Information Request No. 2	Friday, April 1
TGI Response to Commission and Intervener Information Request No. 2	Friday, April 8
TGI Written Final Submission	Tuesday, April 26
Intervener Written Final Submission	Tuesday, May 3
TGI Written Reply Submission	Tuesday, May 10

ATTRIBUTES OF DEFERRAL ACCOUNT AND GAS COST RATE SETTING METHODOLOGIES

Rate Stability

Rate stability refers to both the frequency and the size of rate changes. Customers would generally prefer rate changes to be smaller rather than larger and fewer rather than more, but these goals may conflict if there is a persistent upward or downward trend in gas costs.

Price Transparency

Price transparency refers to whether the gas cost recovery rates reflect market conditions and the overall accuracy of the price signal provided to customers. Setting rates annually generally provides a directionally correct price signal, but rate changes may be too infrequent to provide customers with a good idea of current gas price trends. Setting rates monthly or quarterly provides more frequent feedback, but may lead to oscillations that mask the underlying trend. It may be possible to reduce rate oscillation by setting rates based on the expected cost of gas over the next year rather than the expected cost in the next month or quarter.

Size of Deferral Account

In general, a mechanism that results in relatively small deferral account balances would be preferred to a mechanism that results in relatively large deferral account balances because large deferral accounts can mask underlying commodity price changes and alter the competitive position of the utility relative to smaller gas marketers. Large deferral accounts can also create issues related to the applicability of GCRA rate riders to new customers or customers switching to transportation service that might be avoidable or less important with smaller deferral account balances.

Efficiency of Process

Deferral account and gas cost recovery rate setting mechanisms that are relatively simple are preferred to those that are complex and difficult to understand, and adjustment mechanisms that involve less administration may be preferred to those that involve more administration. Annual review processes may tend to consume fewer resources than more frequent review processes unless the more frequent adjustments are accomplished mechanistically without the need for public input.