CONCENTRIC'S ASSESSMENT OF GAZ MÉTRO'S FINANCIAL DERIVATIVES PROGRAM

TECHNICAL ANALYSIS OF
RUBEN MORENO

September 26, 2013

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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. <u>SCOPE AND PURPOSE OF TESTIMONY</u>

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

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[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

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[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.

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[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.

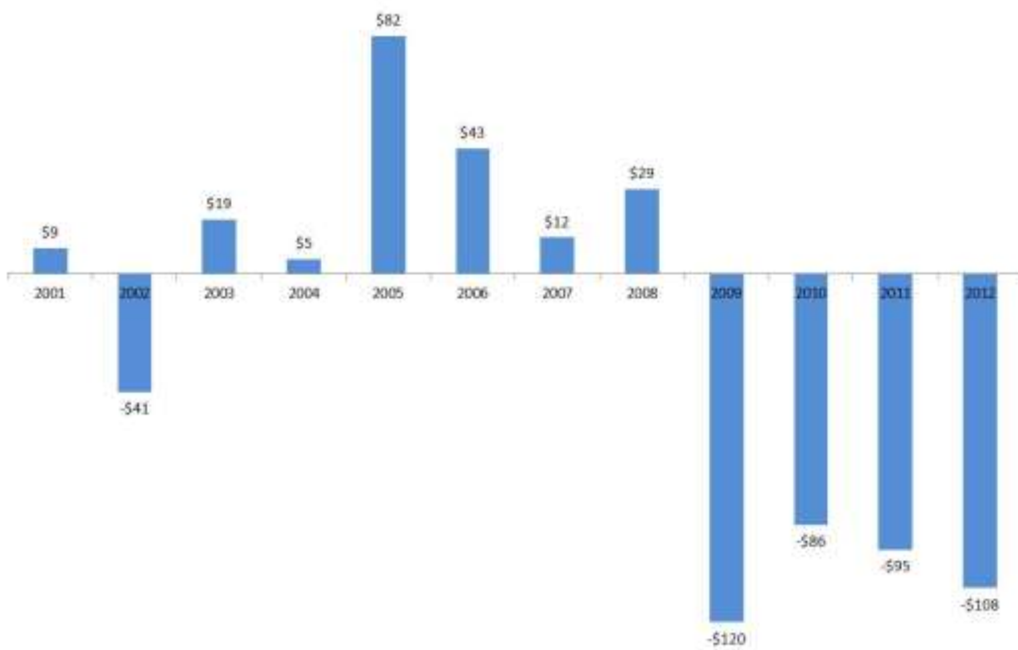

Figure 1: Hedging Gains/(Losses) in Millions of dollars
Source: Gaz Métro

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").

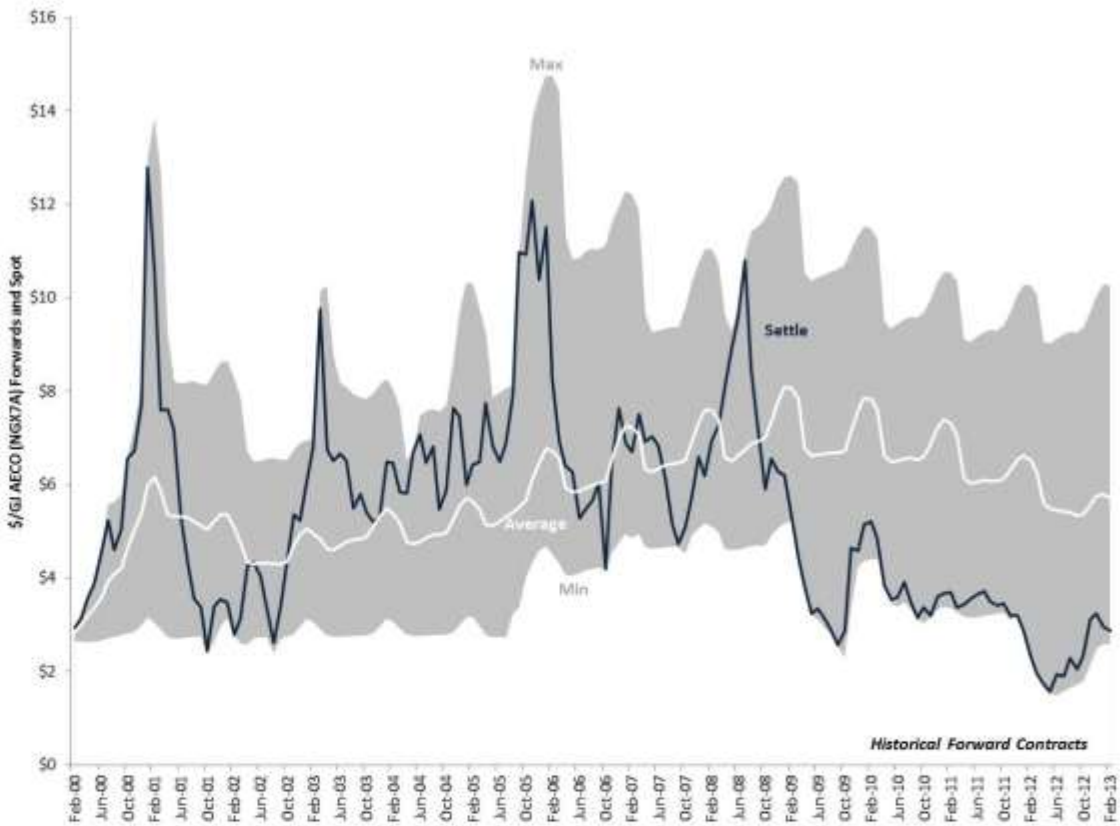

Figure 2: Historical Forward Prices for AECO (Range, Max, Min) and Expiration Price (Settle)

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).

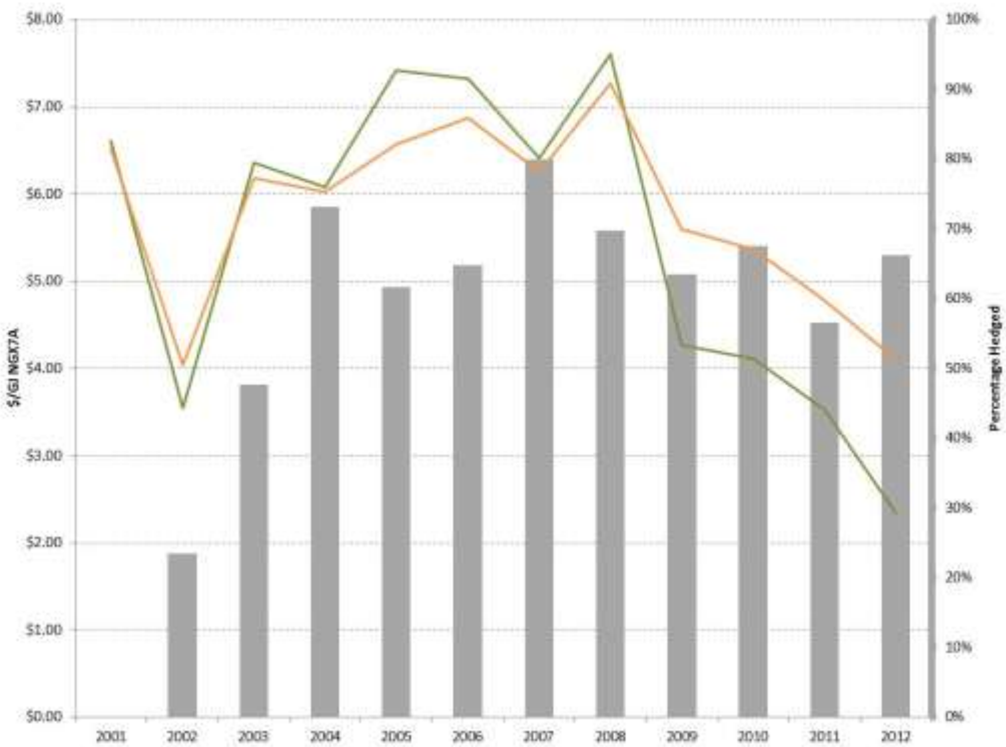

Figure 3: Portfolio Hedge Price (Gold), Unhedged Price (Green) and Implicit Hedged Percentage (bars, right axis)

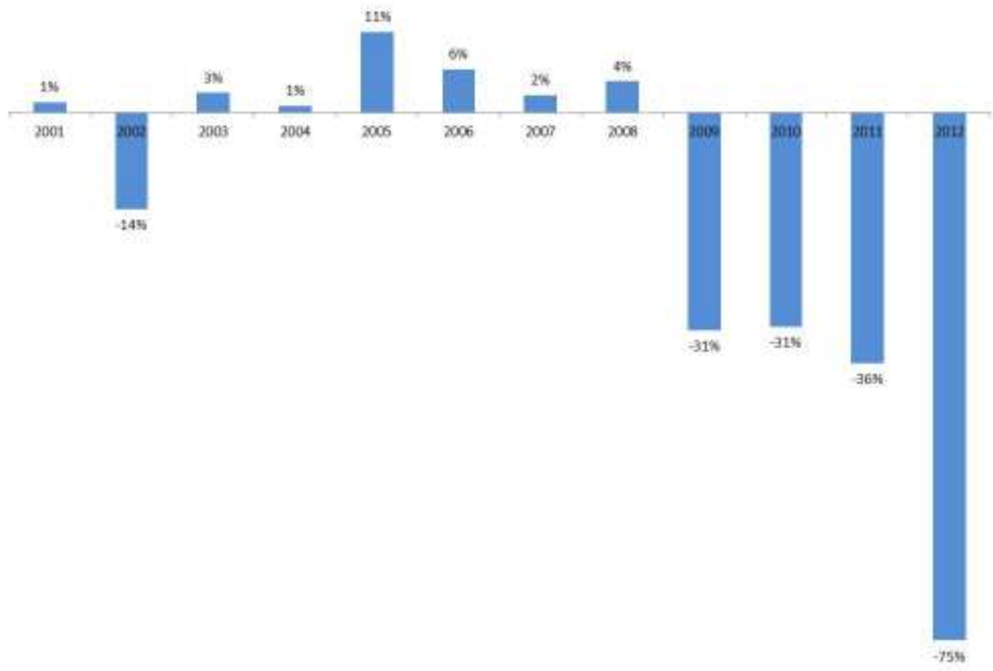

Figure 4: Hedging Gains/(Losses) as a Percentage of Cost without Hedging

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

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[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.

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[20] Ibid.

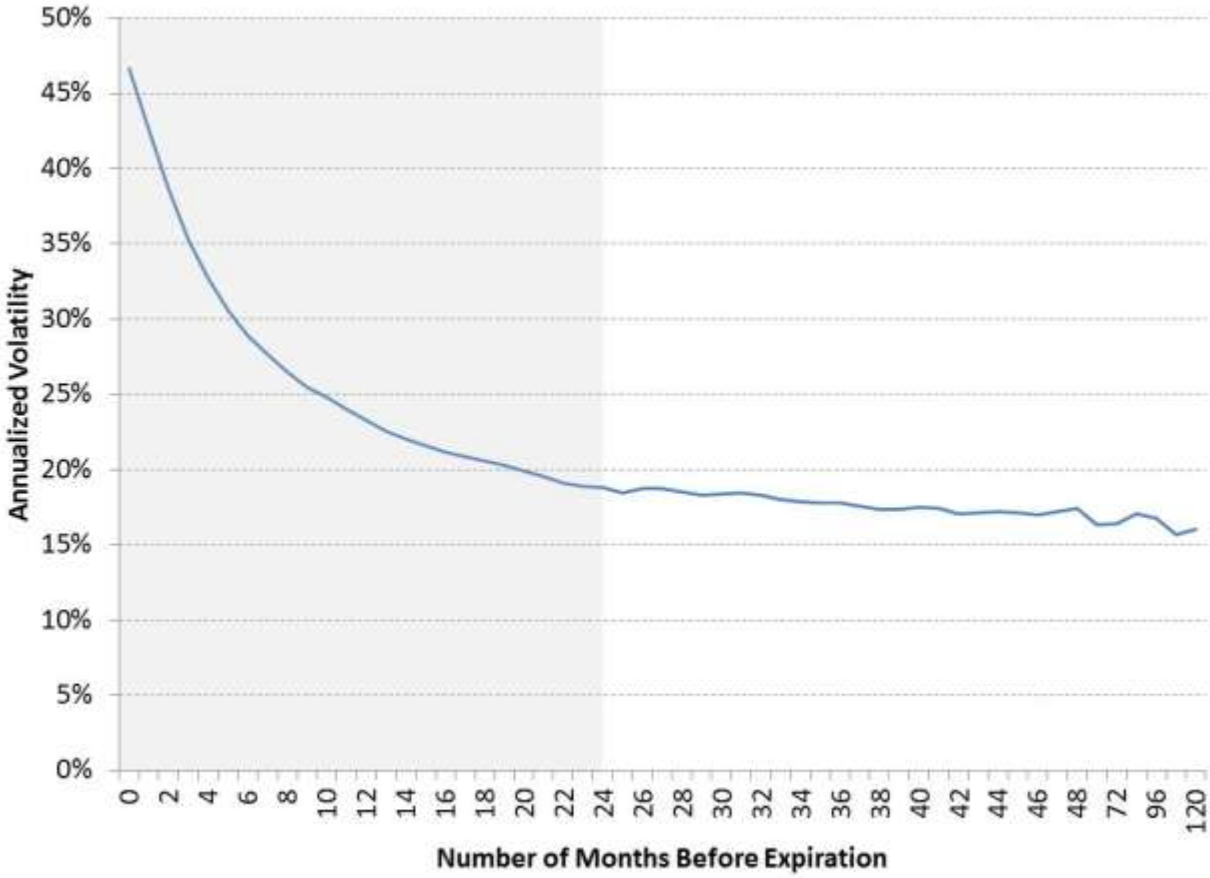

Figure 5: Evolution of Volatility to Expiration for Henry Hub using daily observations from 2003-2013

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).

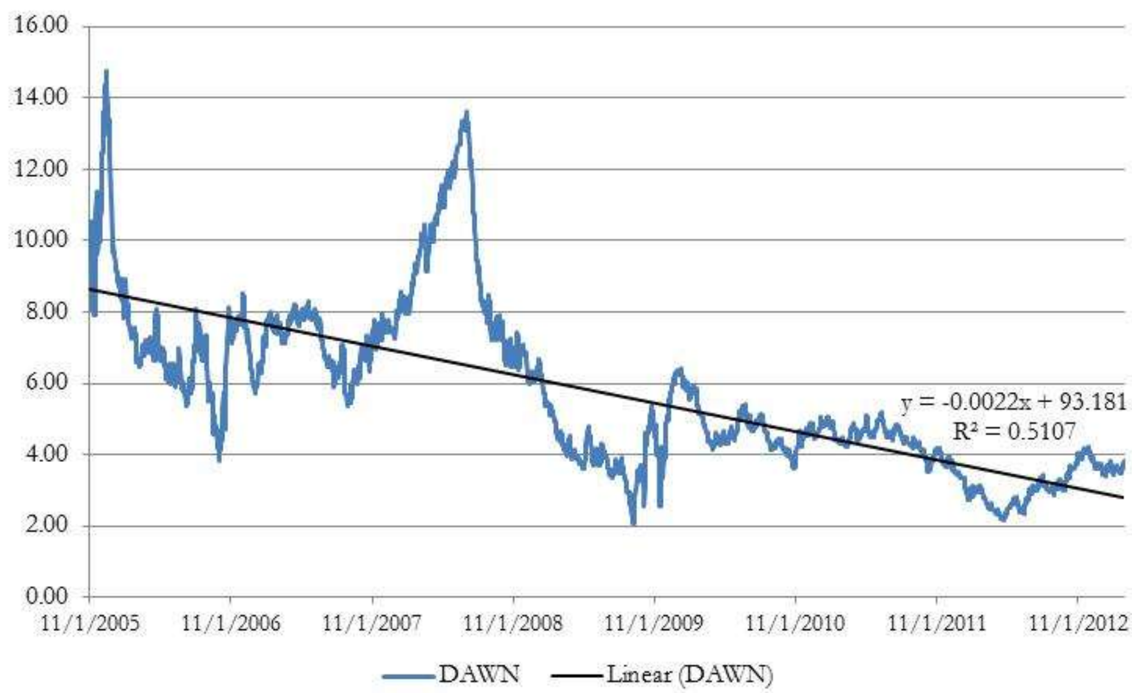

Figure 7: Dawn Spot Price Trend (in US$/MMbtu)

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.

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[22] Navigant Consulting Ltd., *Ontario Wholesale Electricity Market Price Forecast*, Ontario Energy Board, (October 12, 2012)

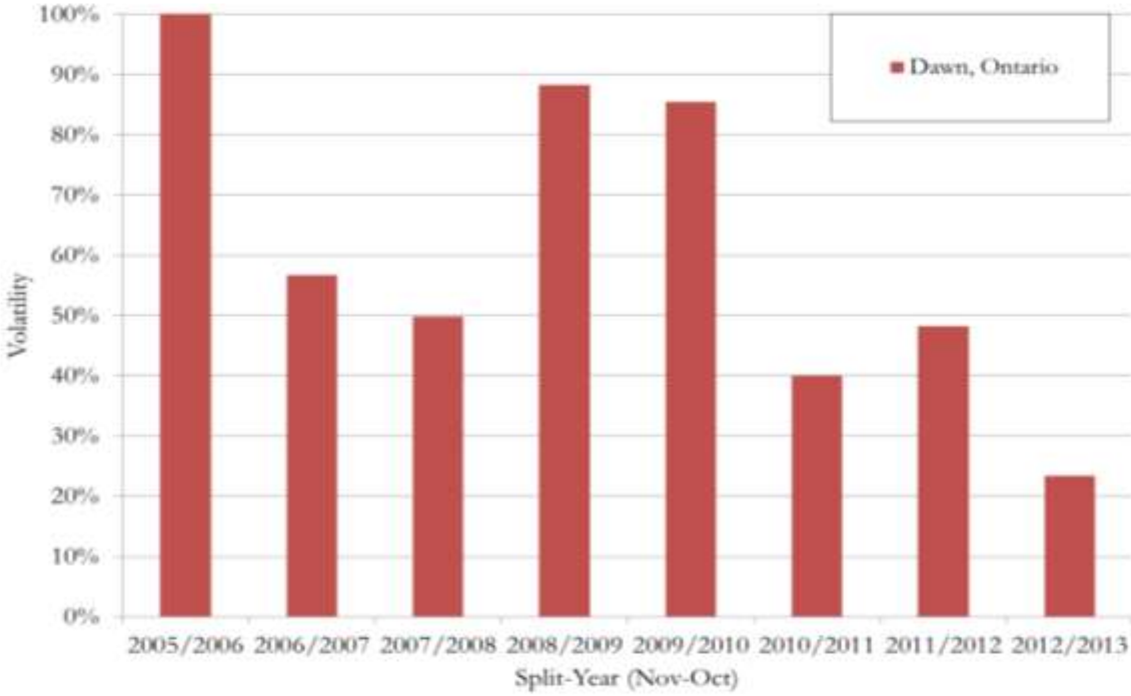

Figure 8: Dawn Spot Volatility[23]

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.

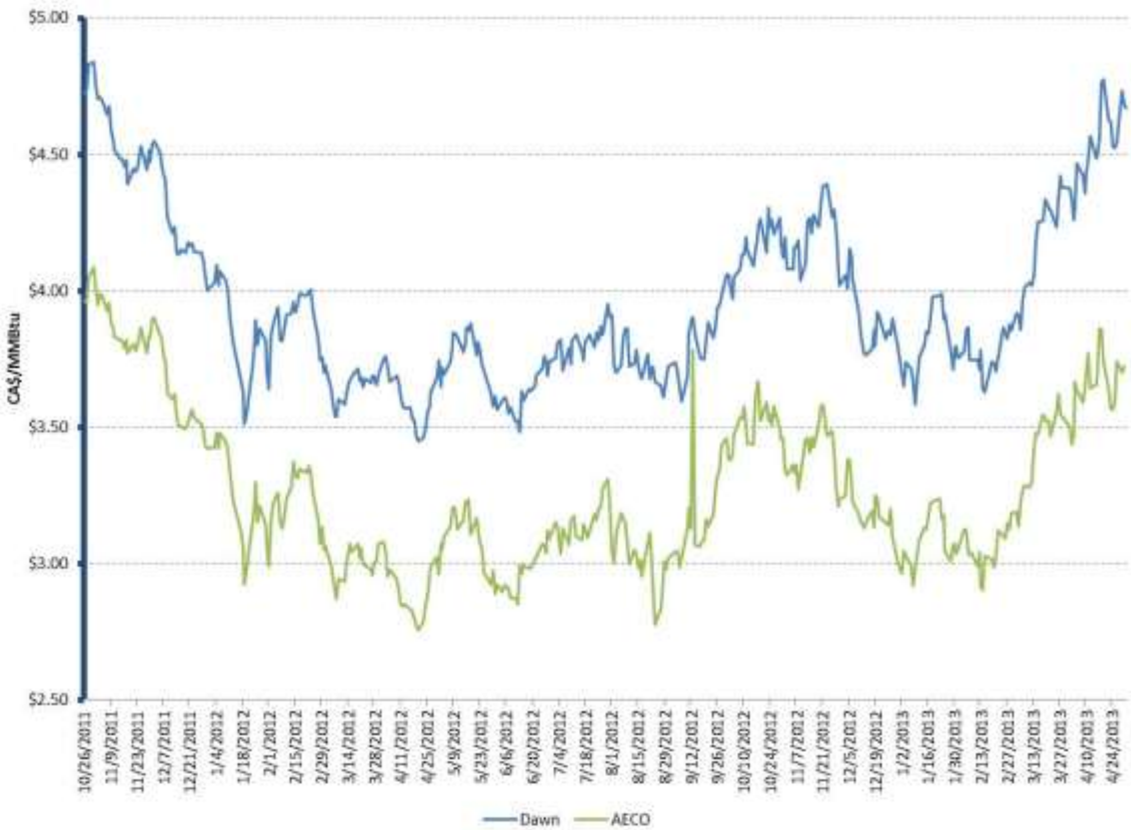

Figure 9: Dawn Vs. AECO Forward Prices for July 2013

Source: Concentric Energy Advisors using data from OTCGH

VIII. *CONCLUSION*

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 70% 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.

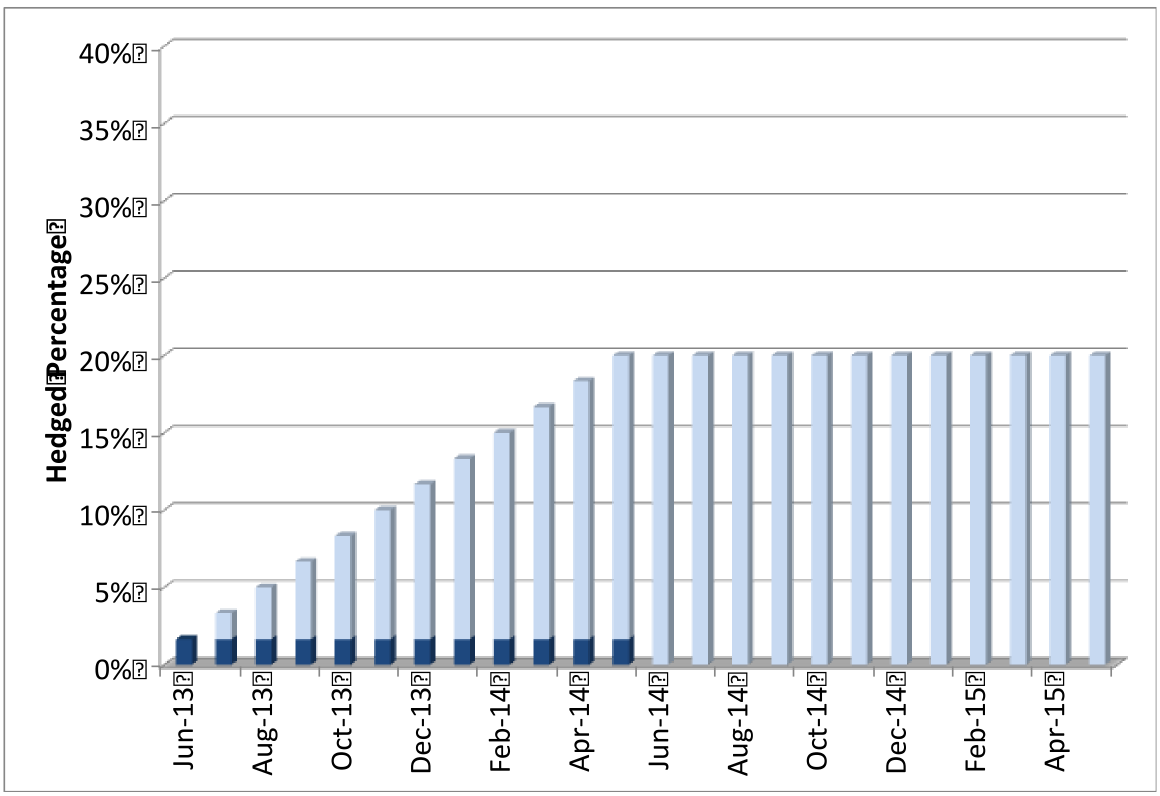

Figure 10: Illustrative Evolution of Hedges for July 2015 Expiration under Programmatic Protocol

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.

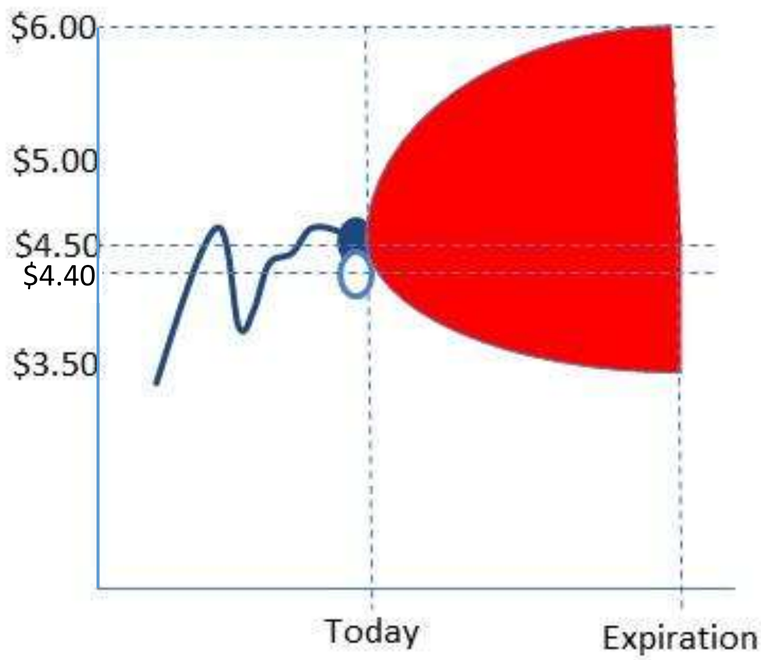

Figure 11: Illustrative Exposure Addressed by Defensive Protocol

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

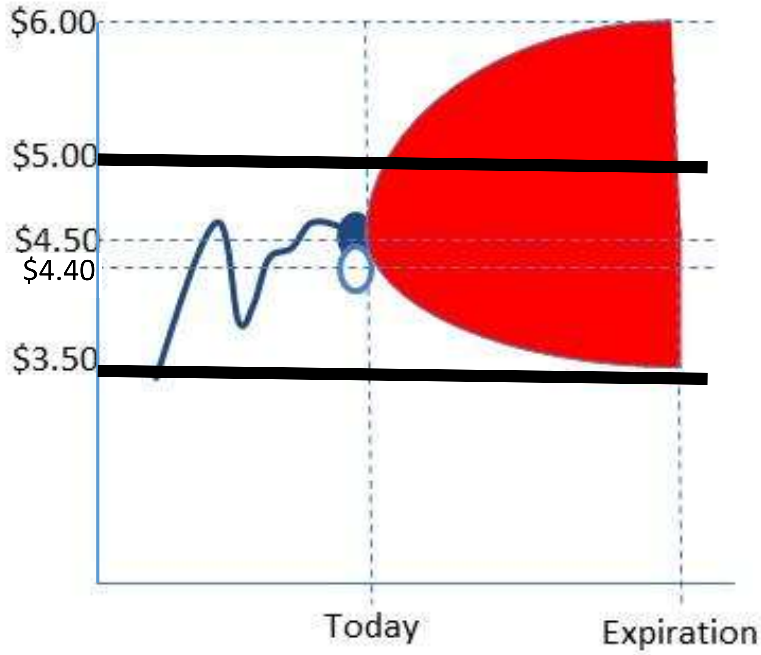

Figure 12: Illustrative Exposure Addressed by Defensive Protocol and Tolerances

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 \$0.60/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.

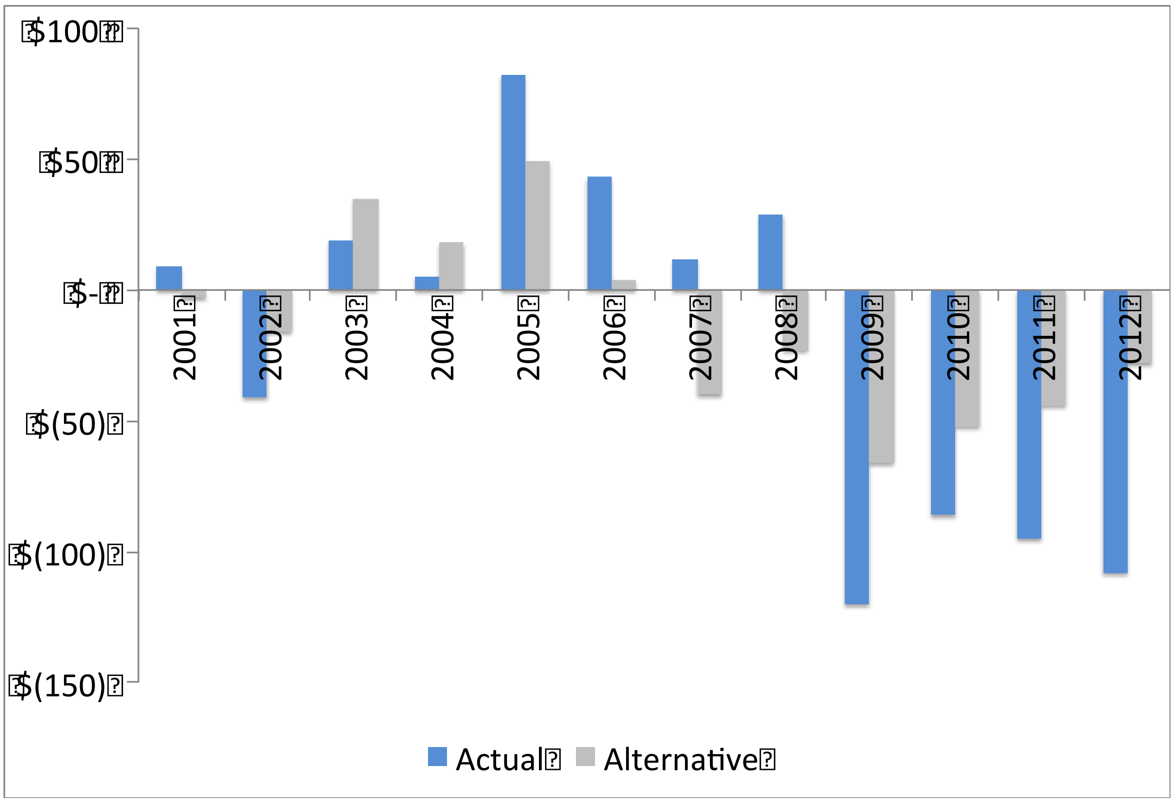

Figure 13: Comparative Opportunity Cost (Historical Vs. Simulation of Proposed Strategy

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.

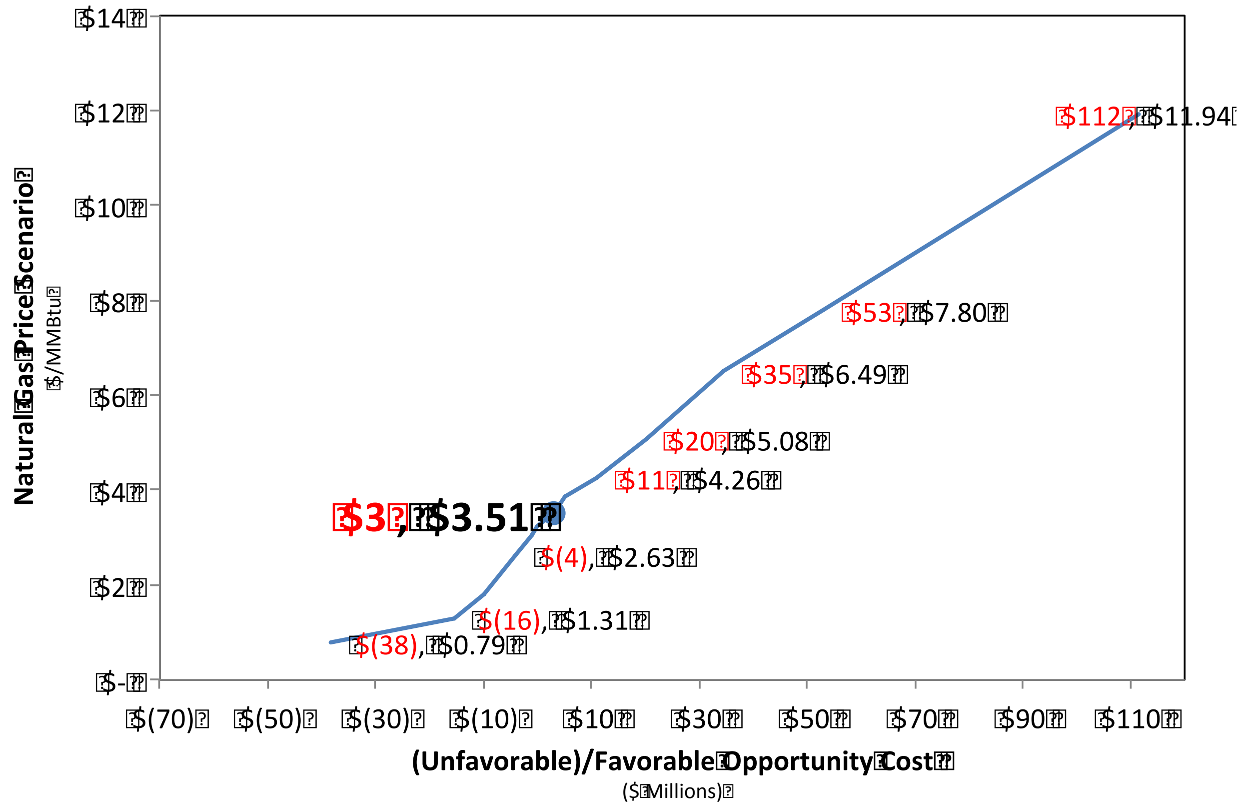

Figure 14: Expected Performance of the Hedging Strategy

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).

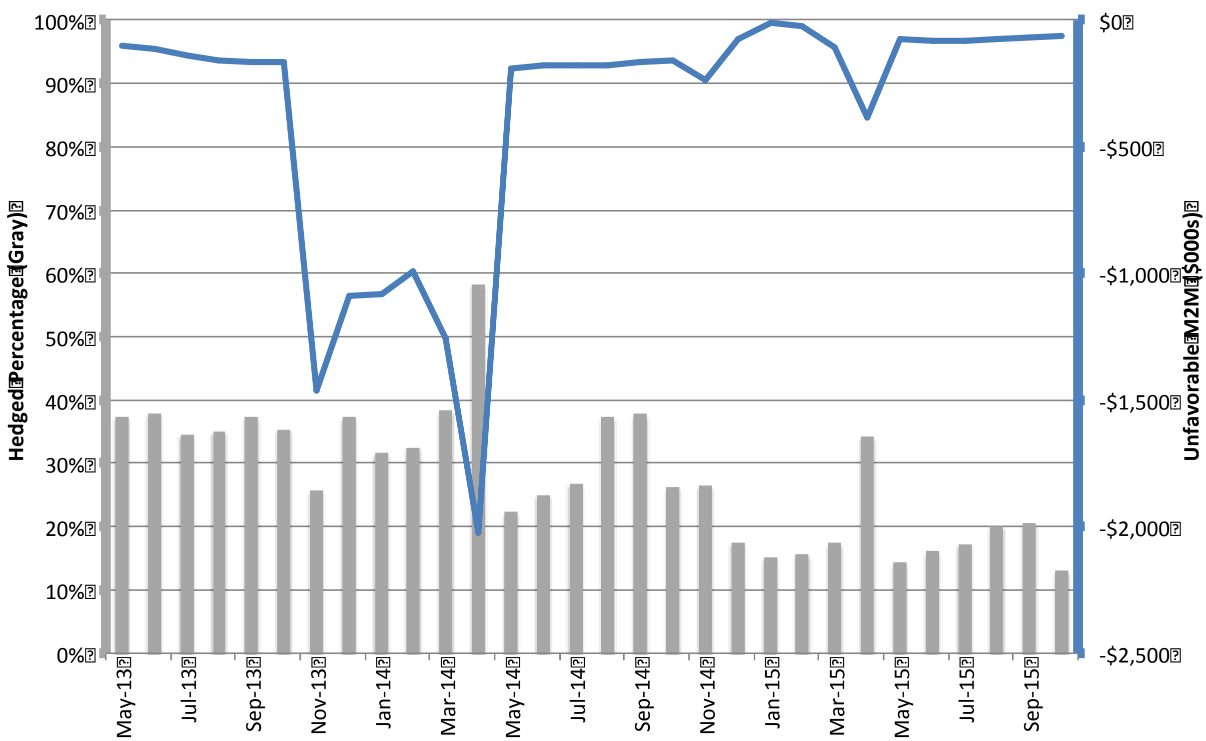

Figure 15: Hedged Position (gray, left) and MTM (blue, right) as of April 30, 2013

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 1.67% of the estimated requirements for July 2015 and 1/12th of 20% (1.67%) 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).

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[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.

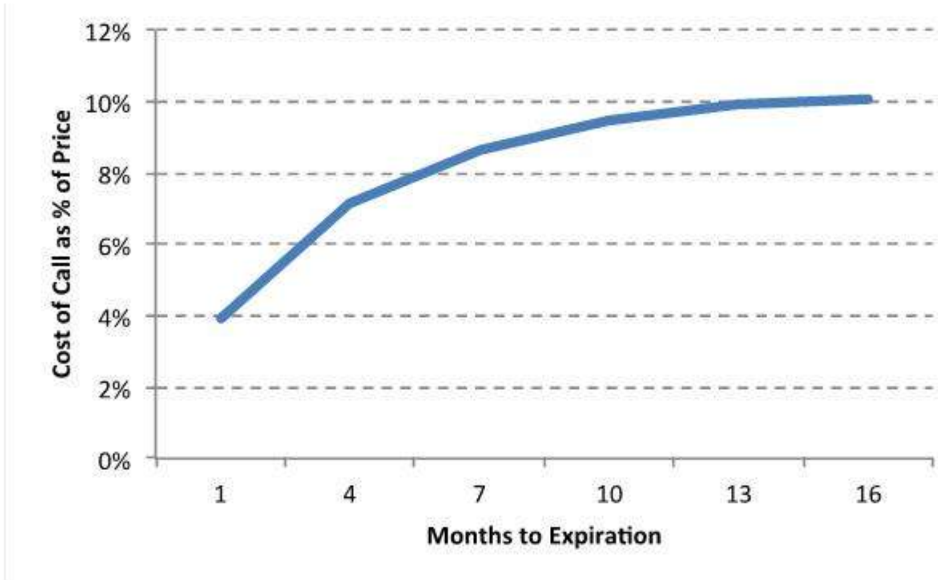

Figure 16: Cost of Call As % of Price of Future Increasing the Time to Expiration

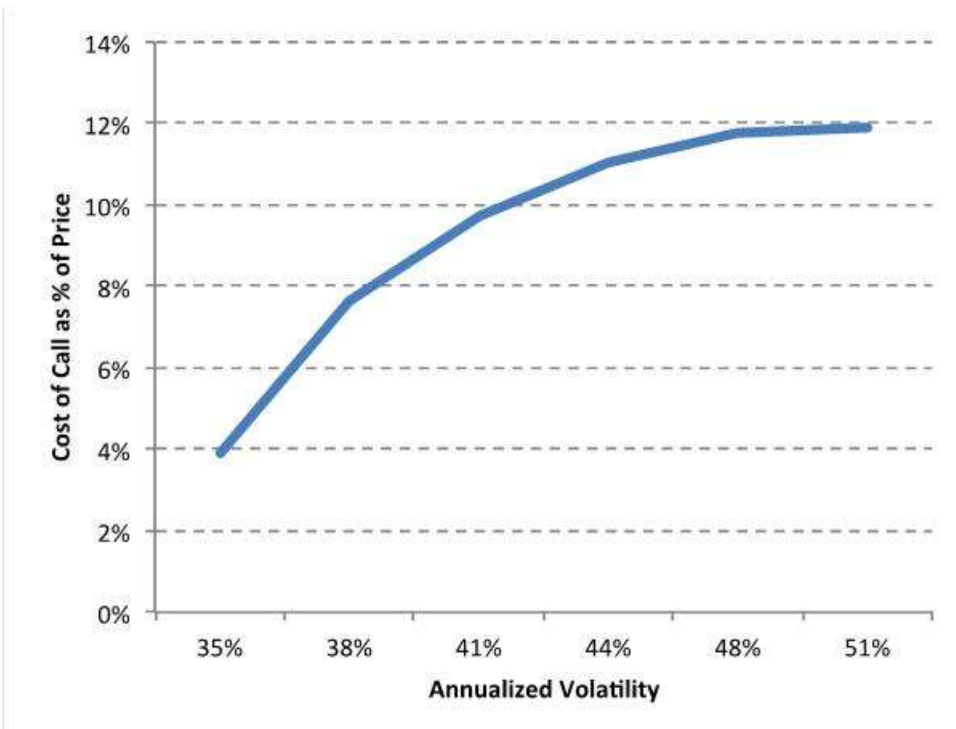

Figure 17: Cost of Call As % of Price of Future Increasing Volatility

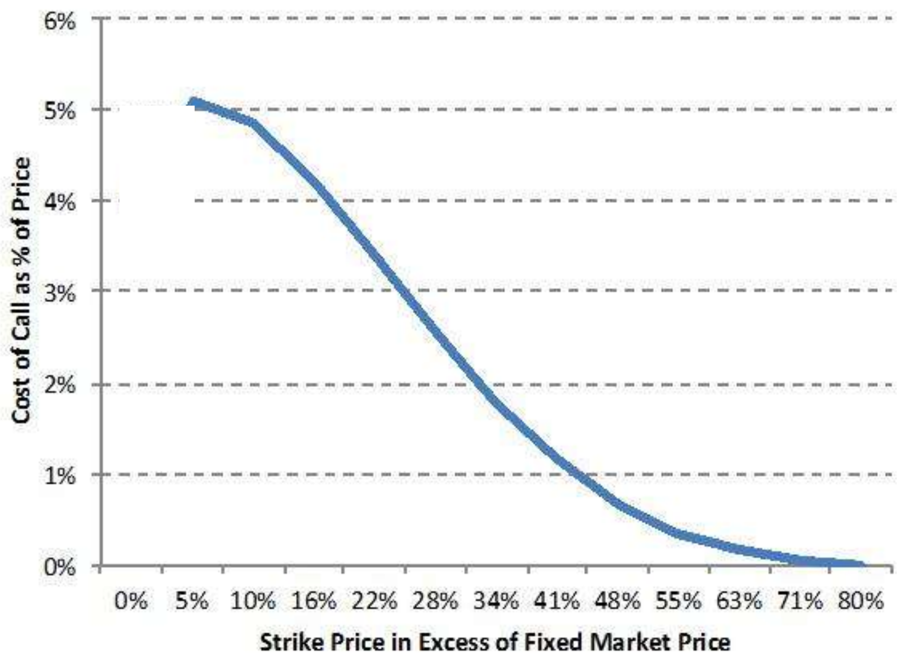

Figure 18: Cost of Call With Increasing Strike Prices

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-Scholes (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;
- 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.

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 CO2 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.

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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

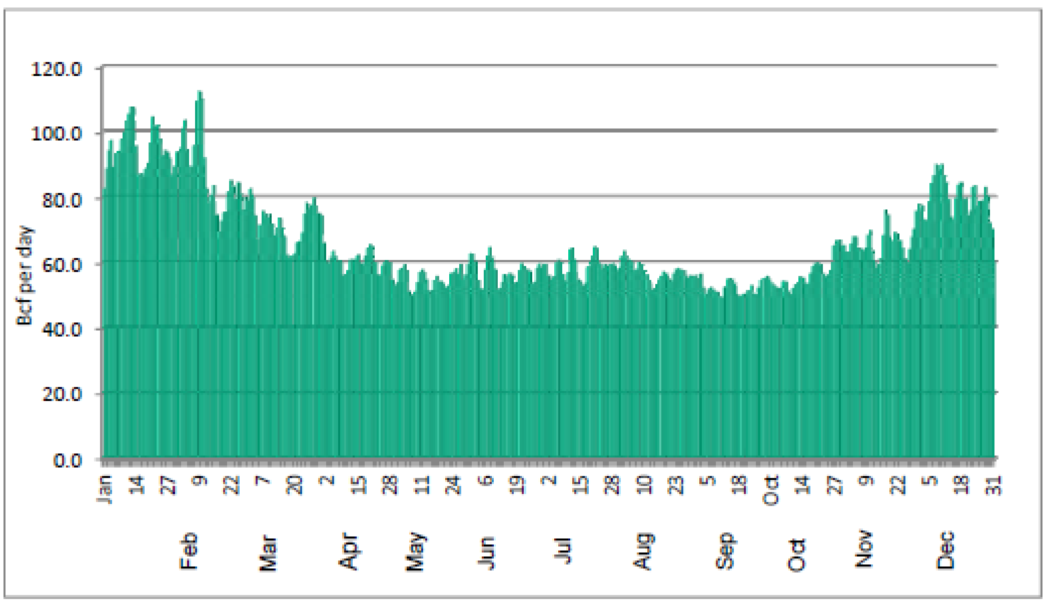
Why does a natural gas utility build a *portfolio* of natural gas supply tools to meet customer requirements during a given winter heating season? While the obvious reason is that companies want to deliver natural gas to customers reliably and at the lowest possible cost, another fundamental motivator 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

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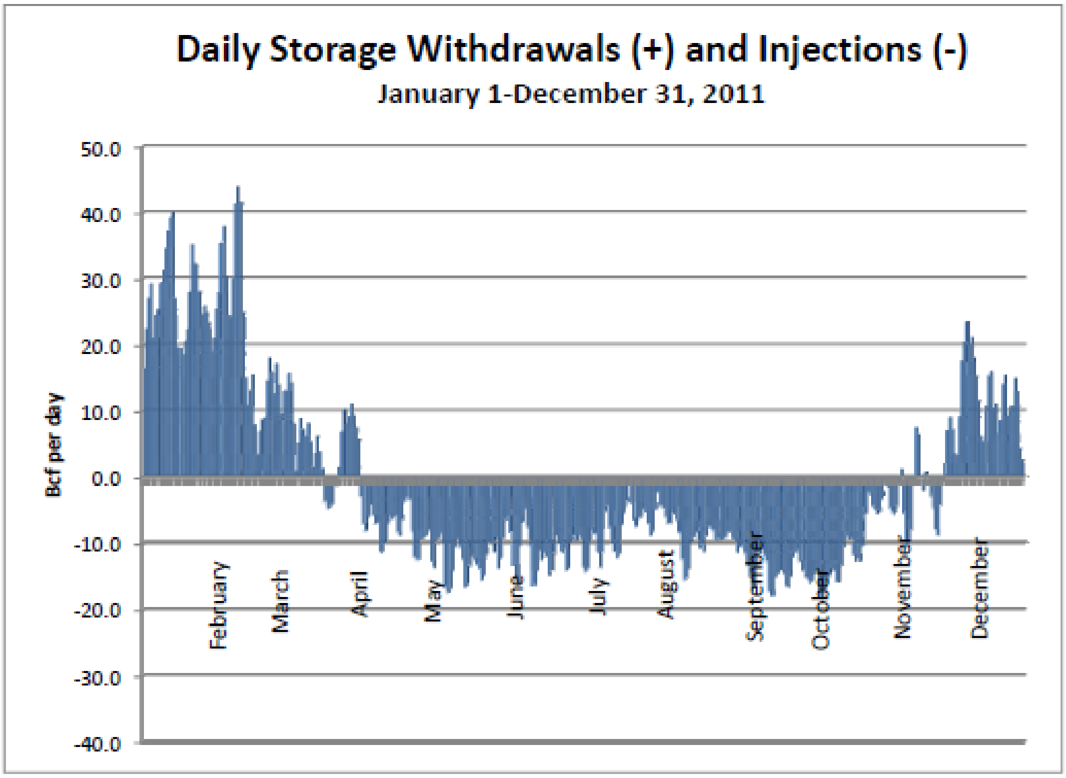
Figure 2 shows the net withdrawals from storage as a positive supply source and the net injections as a demand requirement (below the zero line). A look at only the residential and small commercial sectors provides an even starker example of daily demand fluctuations.

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.

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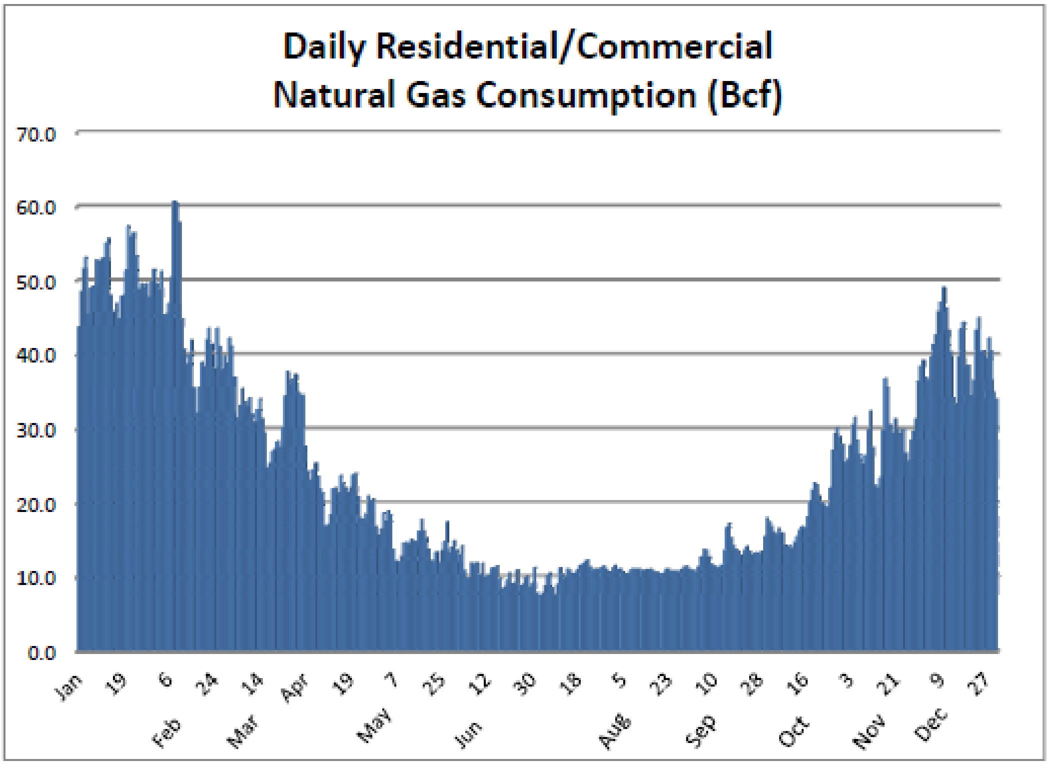
FIGURE 3



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).

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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.

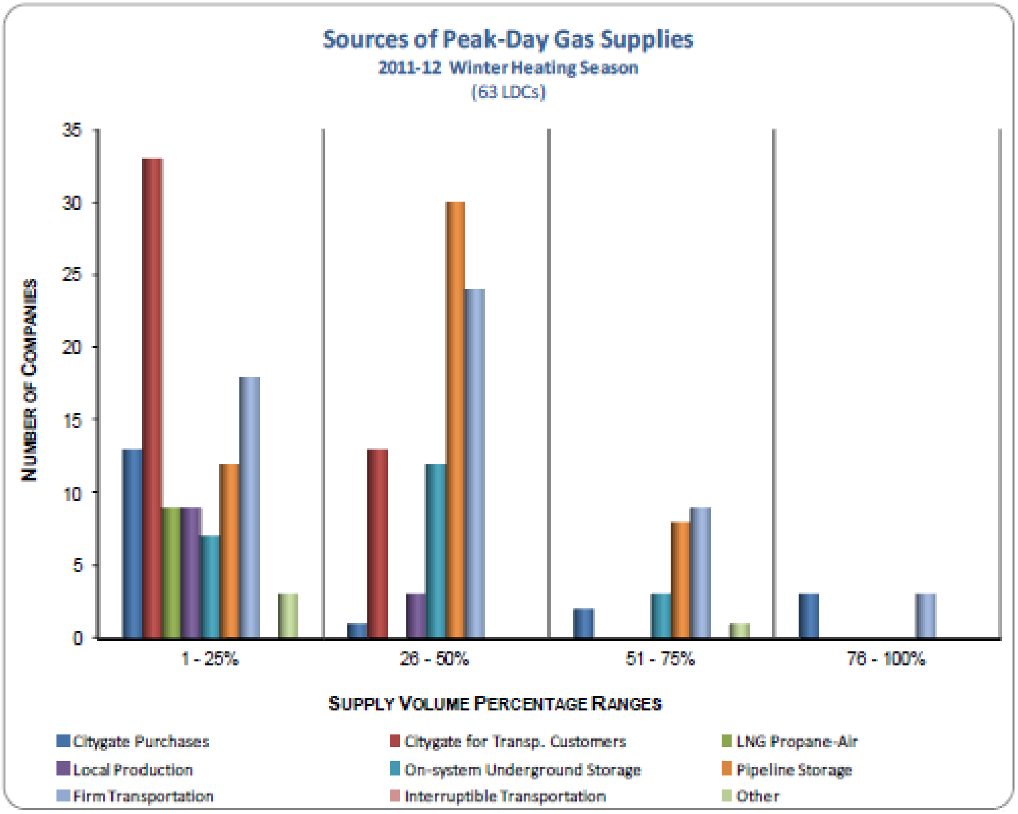
As shown in Table 2, peak-month supplies were heavily weighted toward purchases via firm transportation. As with peak-day supplies, peak-month supplies tended to be supplemented with city gate deliveries for transportation customers, pipeline or other storage, city gate purchases, on-system storage, 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

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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).

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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.

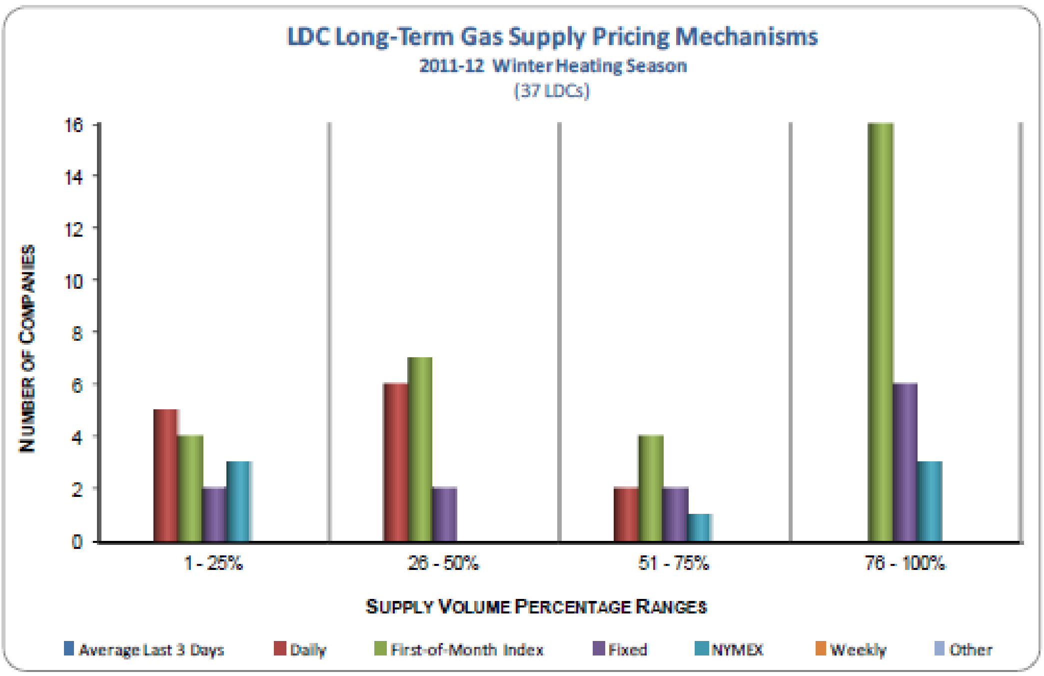
TABLE 6

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

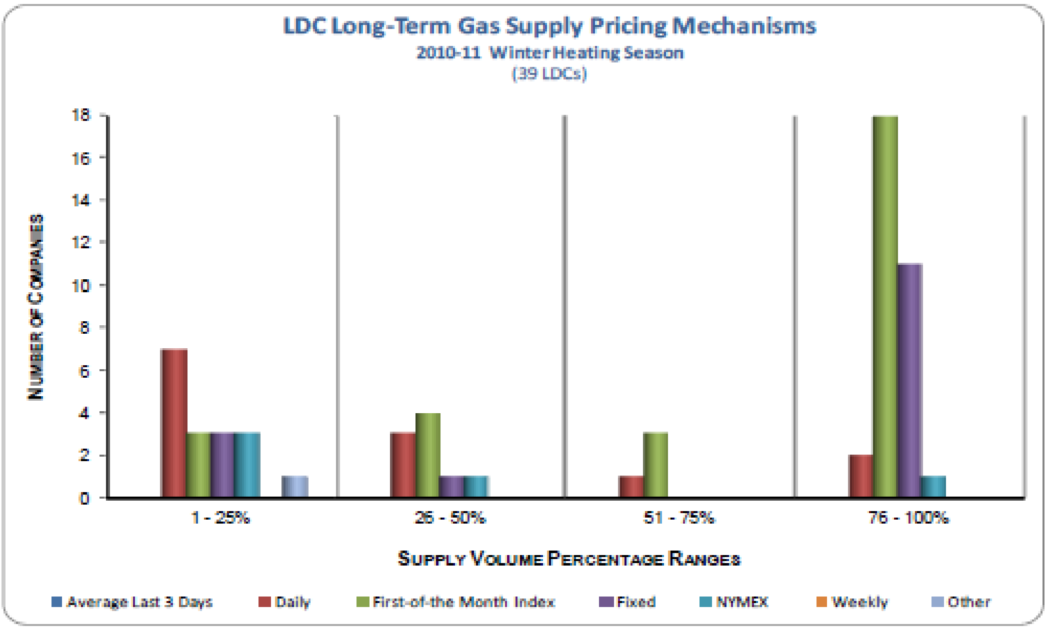
As shown in Table 6 and Figure 5, 31 of the 37 companies with long-term supplies (one year or more) used first-of-month pricing for a portion of these supplies, including twenty companies that used FOM for at least 50 percent of purchases. Thirteen companies used daily pricing mechanisms for long-term 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

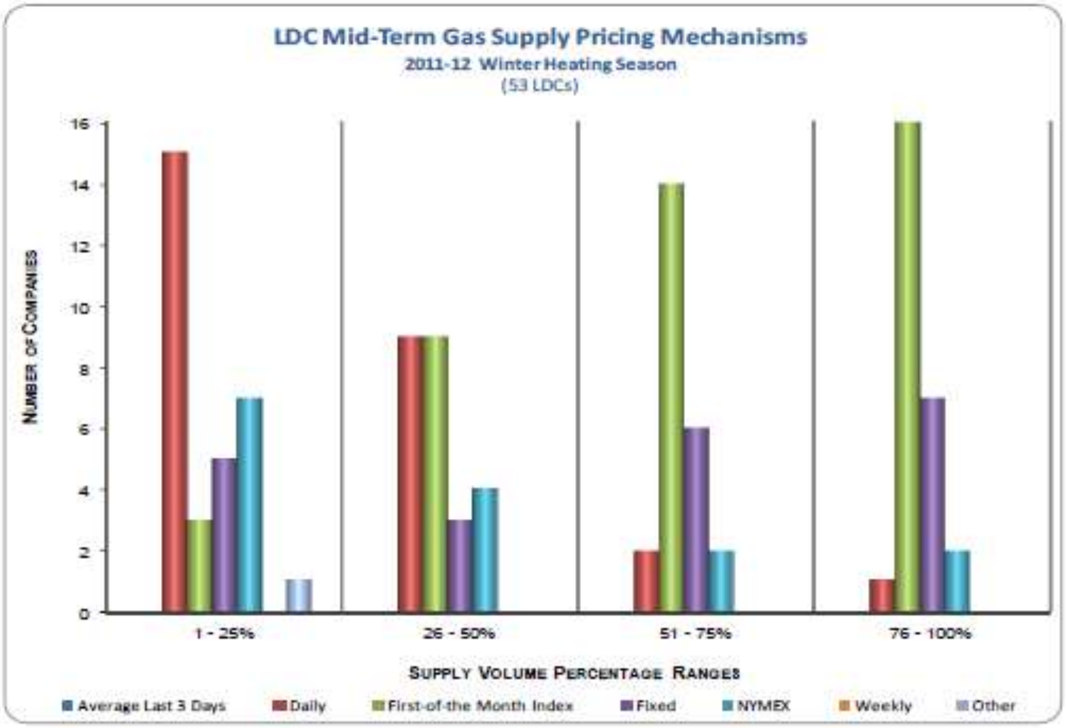
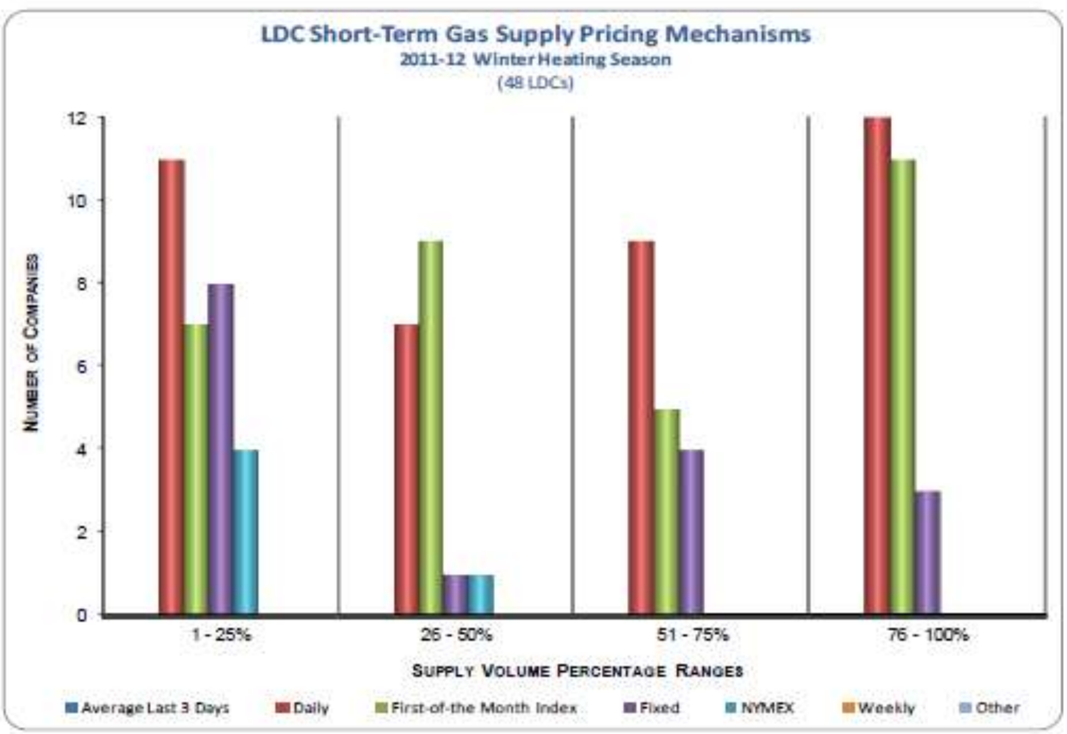


FIGURE 8



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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

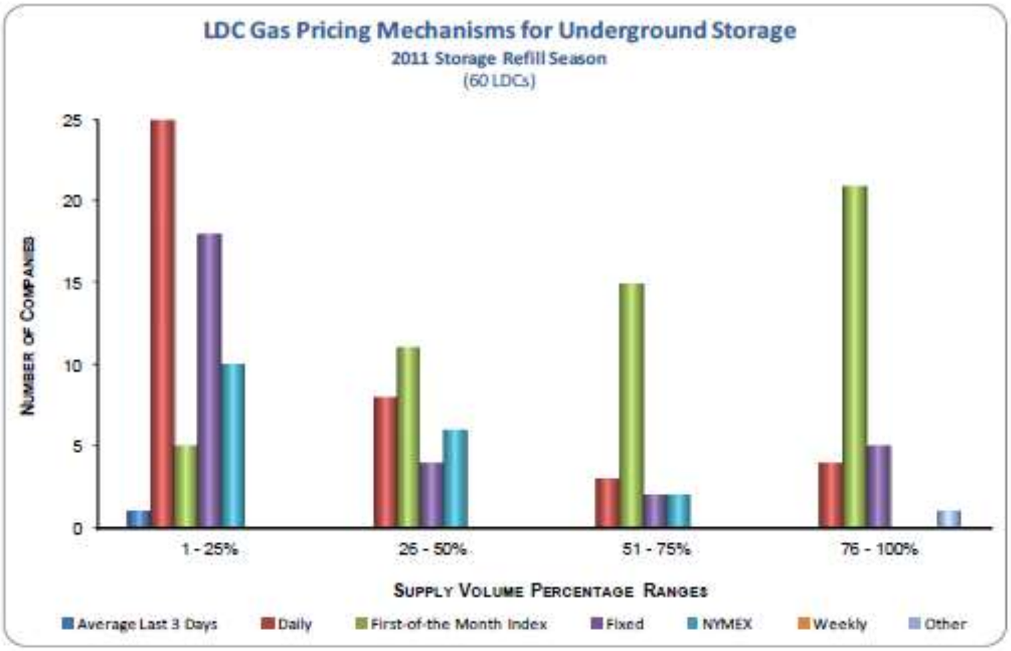
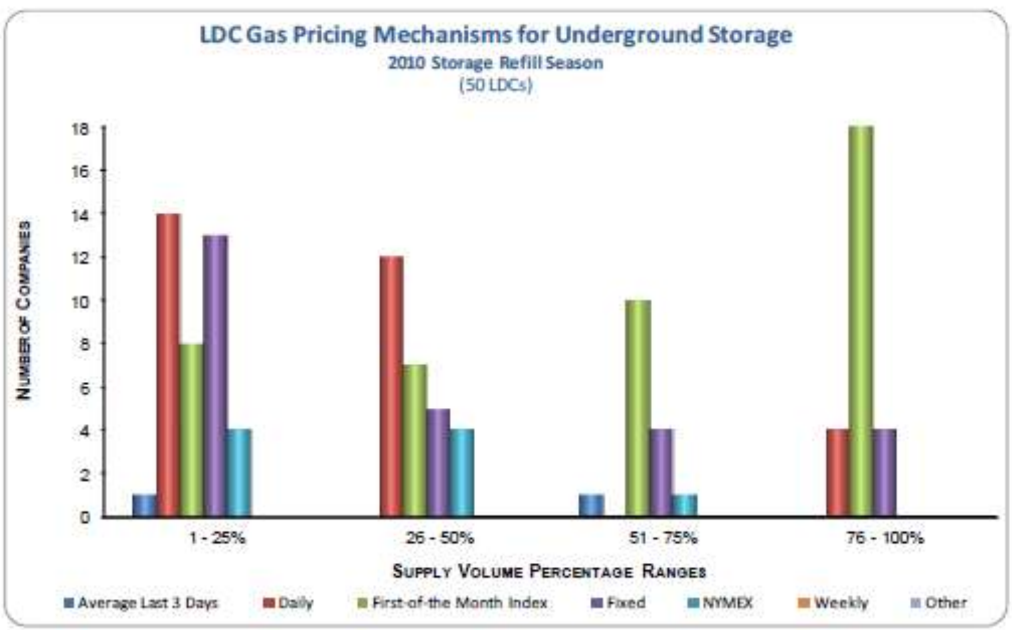


FIGURE 10



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.