**Diane Roy**
Director, Regulatory Affairs - Gas
**FortisBC Energy Inc.**

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7349
Cell: (604) 908-2790
Fax: (604) 576-7074
Email: diane.roy@fortisbc.com
www.fortisbc.com

Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

March 25, 2011

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

**Re: FortisBC Energy Inc. ("FEI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI")[1] (collectively the "Companies")**
**Price Risk Management Review of Objectives and Hedging Strategy and FEI 2011-2014 Price Risk Management Plan ("PRMP")**

**Response to the Commercial Energy Consumers Association of British Columbia ("CEC") Information Request ("IR") No. 1**

On January 27, 2011, the Companies filed the Application as referenced above. In accordance with Commission Order No. G-23-11 setting out the Regulatory Timetable for the review of the Application, the Companies respectfully submit the attached response to response to CEC IR No. 1.

If there are any questions regarding the attached, please contact the Mike Hopkins at (604) 592-7842.

Yours very truly,

**FORTISBC ENERGY INC.**

***Original signed by: Brian Noel***

***For:*** Diane Roy

Attachment

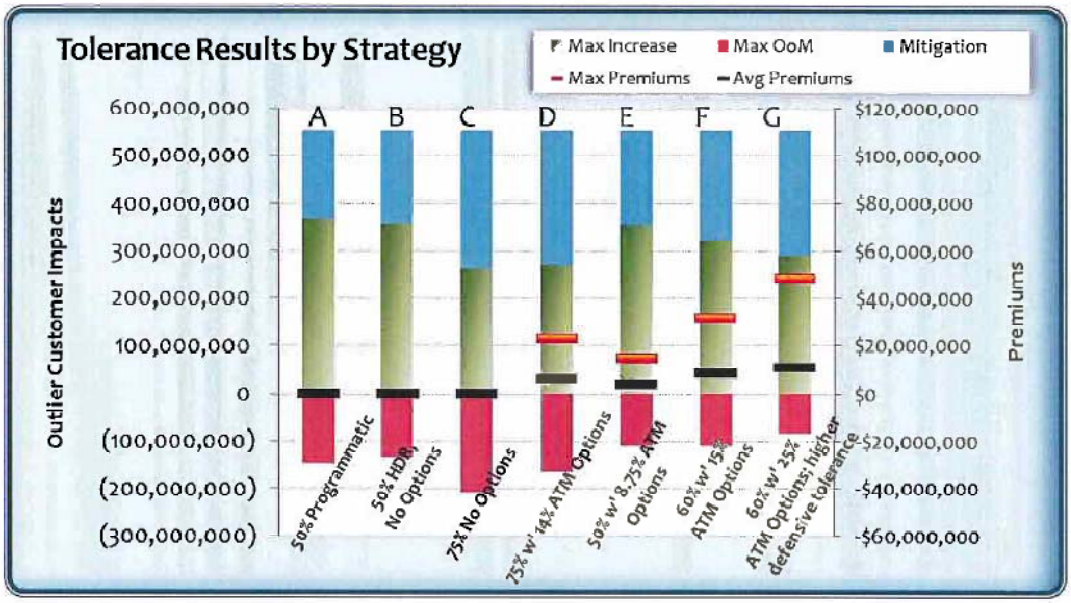
cc (e-mail only): Erica Hamilton, Commission Secretary
Registered Parties

[1] Formerly Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. respectively.

**1. Reference: Exhibit B-1, Page 2 and Appendix A, Risk Centrix Report, Page 6**

for customers. Within the report, consideration of the use of storage and deferral account balances, which mitigate rate volatility to some degree, has also been included. The Company has focused on the importance of the value of price risk management for customers, balancing rate volatility mitigation and competitiveness with reducing the potential costs of hedging. In consultation with Commission staff, an external consultant with extensive experience with utility price risk management, was used for this review. The consultant's review and recommendations are included in this report.

Figure 11, Strategy Assessment Results




1.1 What is the balance between the rate volatility and costs of hedging that FortisBC Utilities (FBU) is seeking?

**Response:**

The Utilities are seeking a balance between rate volatility mitigation, competitiveness and reducing the potential costs of hedging. As discussed in Section 7.1.1 of the Review Report, these objectives are somewhat competing and so finding the optimal balance is key. For example, significantly more hedging than is being proposed would serve to reduce rate volatility even further, however, this may also increase the probability of significant out-of-market hedging costs.

Keeping this desire for balance in mind, RiskCentrix performed some analysis based on different market pricing scenarios to determine the optimal hedging strategy that would balance these objectives. The results presented in Section 7.1.2 and 7.1.3 of the Review Report show that the recommended hedging strategy provides the optimal balance. Table 18 on page 88 shows that the recommended hedging strategy (strategy G in the graph) provides the least amount of potential hedging costs if a low priced market were to occur and the most cost mitigation (i.e. rate increases) if high market prices were to occur. This strategy provides significantly greater cost mitigation in relation to potential hedging costs and so provides the desired balance between rate volatility mitigation and reducing the cost of hedging. Strategies to the left of the graph, with strategy A being similar to the previous hedging program of FEI, provide less cost mitigation but greater potential hedging costs, which is not an optimal solution.

1.2 What is FBU's performance now and where are they expecting to improve to?

**Response:**

Please refer to the responses to BCUC IR 1.1.1.1 and BCOAPO IRs 1.2.2 and 1.2.4 regarding past performance of FortisBC's hedging program. The primary objectives of the PRMP have been met in the past at a reasonable cost over the past 10 years of the hedging program. However, the proposed enhanced hedging program will continue to meet the primary objectives of the PRMP and will also improve the cost effectiveness of the program by being more responsive to changes in market price movements and developments than in previous plans. Reducing the level of programmatic hedging and increasing the use of options in high price or volatility environments will help in this regard.

The expected improvement is illustrated in the referenced graph (Figure 11: Strategy Assessment Results). The proposed PRMP is shown as Strategy G whereas the previous strategy is more closely represented by Strategy A. As summarized in Section 7.1.3 of the Review Report, the recommended strategy demonstrates similar mitigation results while at the same time the likelihood of out-of-the market significant outcomes is reduced.

1.3 Please explain whether or not the Risk Centrix analysis is the FBU choice of balance?

**Response:**

As indicated in referenced Figure 11 of Appendix A of the Review Report, FortisBC believes the recommended strategy by RiskCentrix provides the best balance of reducing the likelihood of significant out-of-the market outcomes, providing mitigation of price increases on the portfolio, and reducing the maximum expected increase to customer bills.

Increasing the use of options, specifically call options, allows FortisBC to realize protection on the upside against price increases while allowing for participation in declining market price environments should prices decline.

1.4 Please clarify exactly what FBU is asking the Commission to approve?

**Response:**

As submitted in the FEI 2011-2014 PRMP, submitted concurrently with the Review Report, the Company is seeking Commission approval per Section 1.1 of the PRMP. In Section 1.1 of the PRMP, FEI requests approval to implement the enhanced hedging strategy as outlined in the PRMP, including the components of programmatic, defensive, value and basis hedging as detailed within the PRMP.

The Utilities filed the Review Report and proposed FEI 2011-2014 PRMP with the Commission on January 27, 2011. As noted in Commission Order G-23-11, following review of the Application and the Commission concluded that prior to making a determination on the need for a hedging program, a written process was *necessary "to review the objectives of the 2011 PRMP"*. This decision has lead to the current review process of the objectives of the plan.

**2. Reference: Exhibit B-1, Page 2**

- Improve the likelihood that natural gas remains competitive with other sources of energy, primarily electricity at this time;
- Moderate the volatility of market gas prices and their effect on rates for customers; and
- Reduce the risk of regional price disconnects.

2.1 Of the 3 objectives outlined above, is it not true that hedging strategies cannot really change the underlying structural competitiveness of energy sources, because the underlying structural issues affecting competitiveness extend well beyond things which can be affected by hedging?

**Response:**

Please refer to the responses to BCUC IRs 1.2.2 and 1.4.1.2.

2.2 Is it not also true that hedging cannot really change the fundamental issues which affect regional disconnections of various reference prices in the market, because these are caused by issues which extend well beyond things which are affected by hedging?

**Response:**

While natural gas hedging cannot change the fundamental issues which affect regional price disconnections, it can reduce the impacts of these price disconnections on gas costs and rates paid by customers. The Utilities recognize that constrained regional infrastructure in its operating region cannot be changed through the use of hedging. Regional infrastructure development, such as the addition of regional pipelines or storage capacity, or reducing demand can serve to change the fundamental issues which affect regional price disconnections. Hedging, and in particular Sumas basis swaps, is an effective means of reducing these price disconnection impacts on customers.

2.3 Isn't it true that the main objective is to deal with volatility of market gas prices and the potential impact this volatility may have on customer retention and attraction?

**Response:**

The main objectives are to reduce rate volatility, maintain competitiveness and reduce the impacts of regional price disconnections at a reasonable cost for customers. The Utilities believe that natural gas rate volatility can adversely impact customer retention in different ways. Firstly, if customers believe that natural gas rates are too volatile for their liking, they may choose another source of energy regardless of whether or not natural gas rates are competitive with this other source of energy, as discussed in Section 4.4.4 of the Review Report. Secondly, natural gas rate volatility that causes natural gas rates to become uncompetitive with other sources of energy would also contribute to customer migration. So, ultimately, reducing rate volatility and maintaining competitiveness are connected.

However, in the absence of rate volatility, it is still an important objective to maintain competitiveness. Uncompetitive rates can occur in the absence of rate volatility. As such, the objectives of reducing rate volatility and maintaining competitiveness are considered separate, but connected, objectives.

**3. Reference: Exhibit B-1, Page 2**

> marketplace in the future (as described in Section 3). The enhanced hedging program recommended within this report is the most effective way to mitigate market price volatility and its impacts on customers' rates.

3.1 Why is hedging the primary focus on methods to deal with customer bill volatility what other mechanism has FBU examined and what choices or conclusions have been made with respect to changing any of the other methods?

**Response:**

Please refer to the responses to BCUC IR 1.8.3 and BCOAPO IR 1.2.1.

**4. Reference: Exhibit B-1, Page 3**

RiskCentrix hedging strategy includes several key elements:

- Programmatic hedging for scheduled volatility reduction;
- Defensive hedging to respond to potential increases in prices above specific tolerances;
- Value hedging to capture favourable price opportunities; and
- Basis swaps for managing Sumas price exposure.

The strategy involves finding an appropriate balance between customer volatility tolerances, hedging cost (or out-of-market) tolerances and option expenditures. A greater use of options than in past hedging programs is recommended as these instruments provide effective upside cost mitigation while also reducing the potential out-of-the-money outcomes.

4.1 Can FBU identify quantitatively what the added value is for adopting the Risk Centrix recommendations?

**Response:**

As discussed in Section 7.1.3 of the Review Report, the RiskCentrix analysis shows that the recommended hedging strategy significantly increases portfolio gas cost mitigation while significantly decreasing potential out-of-market hedging costs. Table 18 on page 88 of the Review Report shows these results, with strategy A representing the previous FEI hedging program and strategy G representing the FEI proposed hedging program. The proposed hedging program, if approved, will improve FEI's ability to meet the objectives at a lower expected cost. Please also see the response to CEC IR 1.1.1.

**5. Reference: Exhibit B-1, Page 7**

> Price risk management is typically defined as taking appropriate measures to reduce exposure to uncertainty in future market prices. RiskCentrix describes price risk management as defending against intolerable outcomes and notes that the magnitude of risk in the natural gas marketplace is greater to the upside than the downside - prices are bounded by zero at the bottom but unlimited on the top[1]. In general, natural gas utilities use price risk management in costs on a consistent basis. Furthermore, hedging should not be considered a profit-making endeavour. This would typically involve speculating on future price movements and potentially expose customers to even greater market price risk in the event that predictions are wrong.

5.1 If the price risk issue is about avoiding intolerable outcomes such as customers leaving use of the natural gas energy resource because of price volatility, does FBU track leaving customers and survey reasons for leaving and use this as a measure for determining benefits?

**Response:**

FEI has attempted to collect information about why customers choose to stop using natural gas. However, collecting feedback from customers that choose to defect is complicated by the limited window available to identify and call them. Ideally, FEI could evaluate those individuals that occupy premises that have not consumed natural gas for over a year. These premises more often represent permanent customer losses because the longer a service remains unused, the less likely it will be used in the future. Unfortunately, individuals at these premises are no longer our customers and FEI has no reliable contact information for them. To try to deal with these issues, FEI commissioned Synovate, a market research company, to conduct a study[1] designed to understand the reasons for customer defections and to help identify the risk factors of attrition. Telephone interviews were conducted with FortisBC Energy Utility ("FEU") customers who recently requested a final read and disconnect or advised the company that they were moving.

The Synovate study included a sample of 553 customers. Of these, 151 asked the Company to close their account or disconnect their meter (i.e. self-identified as "Disconnects"). The remaining 402 advised the Company that they were moving (i.e. self-identified as "Moves"). Data collection took place between December 7, 2010 and February 4, 2011. Fewer than 2% (nine customers) of total lapsed customers surveyed reported switching to another fuel type. Of those, six customers indicated they were switching to electricity; one was switching to propane, and the remaining two were undecided. Four of the nine customers that indicated they were switching to another fuel, mentioned that the main reason for switching is because "that's what's

[1] Terasen Gas Customer Attrition Survey Report, Synovate, February 28, 2011.

in the new residence." One respondent indicated they were switching to a cheaper fuel; one indicated that natural gas is not available in the new residence; and three customers gave no reason in particular.

FEI believes that the low incidence of fuel switching indicated in the study accurately reflects that the occurrence rate is only evident in a small proportion of the Company's overall customer base. Reaching consumers that have opted for an alternate fuel product is difficult. Typically, these individuals are no longer an FEU customer and they cannot be reached by phone. Sample size restrictions make it cost prohibitive to understand and quantify all the reasons why customers decide to switch fuels/energy providers. However, FEI is of the opinion that volatile commodity prices and steep price spikes are inconsistent with the Company's efforts to retain customers and ensure that commodity costs remain fair and reasonable. Importantly, even the low rates of fuel switching evident in the Synovate Customer Attrition Survey can accumulate quickly over several years to result in significant customer and load loss. That prospect is detrimental to all remaining customers.

5.2 Does FBU allocate the price risk reduction benefit among the contributing strategies for controlling the tolerable level of price change?

**Response:**

FEI does allocate the price risk reduction benefit among the contributing strategies for controlling the tolerable level of rate changes. As discussed in Section 8.2 of the Review Report, the defensive hedging strategy price triggers have been developed based on consideration of customers' tolerable bill preferences (as well as electric equivalent benchmarks). This hedging strategy enables price risk reduction in terms of customers' tolerances and is implemented only when market prices are expected (based on market price volatility) to breach these predefined tolerances.

**6. Reference: Exhibit B-1, Page 8**

> Natural gas utility customers have indicated that they desire some level of stability in natural gas rates and implicit protection from the volatility in market prices. Customer complaints and media

6.1 Has FBU determined the tolerance levels for price change for customers at the margin, who may be the ones more susceptible to leaving rather than having just surveyed and looked at average tolerance across the whole customer population?

**Response:**

The Utilities have not specifically determined the tolerance levels for price change for customers at the margin. However, the Residential Customer Price Volatility Preferences Study (the "Study"), provided in Appendix B of the Review Report, did reveal insights into tolerance levels for customers with different billing amounts. As discussed on page 4 of the Study, the results revealed:

> *"As might be expected, the maximum change in annual gas billings that participants say they can live with tends to increase as their annual gas billings increase. Results show that for total annual natural gas billings of less than $900, the average amount of change participants could live within their annual gas billings was $53 (or 11% of total annual billings under $900). For total annual natural gas billings of $900 or more, the average amount of change per year participants could live with was $219 (or 17% of total annual billings of $900 and over)."*

This research indicates that those customers with smaller bills are more sensitive and have less tolerance for rate changes. As such, it could be inferred that customers at the margin have lower tolerance levels for rate changes than the average of the whole customer population.

**7. Reference: Exhibit B-1, Page 8**

> Reducing natural gas rate variability helps gas utilities to maintain or grow their customer base. If natural gas rates are not competitive or too volatile for customers, declining throughput on the natural gas system places upward pressure on the per unit (or per customer) distribution and delivery costs, all else equal, for those customers that remain with natural gas service.

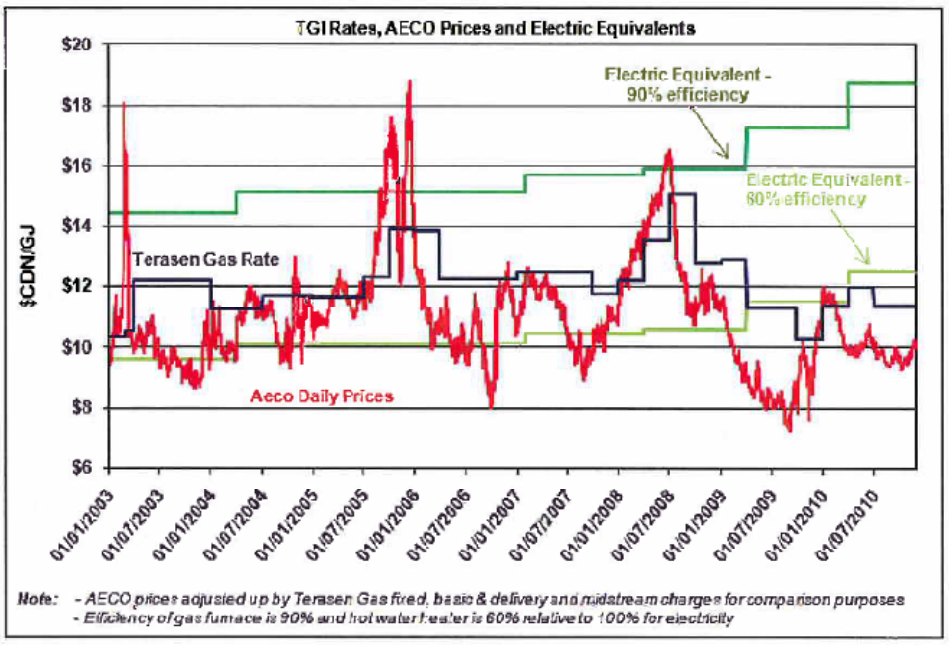
7.1 Has FBU determined how much the structural competitiveness of natural gas influences customer retention and attraction versus the volatility of price changes?

**Response:**

The term "structural competitiveness" is unclear in this question. FBU interprets this phrase to mean the full rate competitiveness of natural gas versus other fuels. FBU has not conducted any studies to assess the magnitude of the impact of rate competitiveness on customer retention and attraction versus the magnitude of the impact of commodity price volatility. Both aspects of energy costs can have an impact on customer retention and attraction and must be actively managed to maintain customer satisfaction. Managing price volatility will reduce the impact of price spikes and regional price disconnects that increase energy costs for our customers and is integral to managing natural gas rate competitiveness. Separating the two aspects for such a comparative analysis would be very difficult. Further, customers have indicated to the Utility, through focus groups and customer survey, that some form of price volatility reduction is preferred over a fully based market rate.

**8. Reference: Exhibit B-1, Figure 1, Page 10**

Figure 1: TGI Rate Compared to Market Gas Prices and Electric Equivalents




8.1 This record of past performance regarding price volatility shows about a 20% to 30% price jump response to market peaks. Can FBU identify how much the price peaks have been dampened by the hedging and how much is being dampened by the periodic delayed price change smoothing, for this actual past record?

**Response:**

Please refer to the responses to BCOAPO IRs 1.2.1, 1.2.2, and 1.2.4.

8.2 Could customer perceived price change be greatly reduced by use of a longer smoothing period and more frequent increments for introducing small step changes to customers?

**Response:**

The Company's view is that frequent rate changes, however minor in magnitude, can still be interpreted by customers as rate volatility. For instance, if rates increase for a number of

consecutive periods, this can possibly lead to the perception that rates will keep increasing in this manner in the future.

Deferral account balances help reduce the volatility in rates but do nothing to affect the underlying price of the commodity which is still subject to volatility in market prices for natural gas. Customer rates would still eventually have to catch up for any variances captured in the deferral account. On February 5, 2001, the Commission issued Commission Letter No. L-5-01 which included the Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance (the "Guidelines") as Appendix I. The Company's current quarterly review and resetting process related to the commodity rate is consistent with the Commission established Guidelines.

Further, Appendix II to Commission Letter No. L-5-01 contained a document titled Attributes of Deferral Account and Gas Cost Rate Setting Methodologies, which discussed the various attributes of deferral account and rate setting methodologies including rate stability, price transparency, implications for the expected size of the deferral account, and efficiency of process. Any changes to the length of the prospective period used in setting commodity rates and/or to the frequency of rate changes could materially affect the balance of the various objectives related to rate stability, price transparency, managing the size of the deferral balances, and administrative efficiency.

As discussed in Section 4.5.1 and 4.5.1.2 of the Review Report, customers have indicated that they are willing to tolerate a certain acceptable amount of volatility in their rates but also prefer rate stability as well. FortisBC believes that increasing the number of potential rate changes will lead to outcomes not preferred by customers as indicated in various surveys and focus groups.

FortisBC believes that deferral account balances and EPP should be complementary to an effective hedging program that strives to manage the underlying volatility inherent in market prices.

8.3 Please show what the Terasen gas rate would have been and would have graphically looked like had the rate smoothing period been 18 month and 24 months with price changes being implemented every two months and every month respectively?

**Response:**

The graph shown in Figure 1 in Section 2.4.1 of the Review Report has been revised, and attached below, to include (1) a line to provide a proxy of what the FEI rate would have been if the commodity recovery component of rates had been set based on an 18-month prospective

basis, and (2) a line to provide a proxy of what the FEI rate would have been if the commodity recovery component of rates had been set based on a 24-month prospective basis.

FEI notes that the analysis completed to calculate the 18-month and 24-month commodity rates has been based on the historical gas cost forecasts as utilized in the Company's quarterly gas cost filings and, as such, the rate changes have been calculated on a quarterly basis – historical gas cost forecasts, updated each month for changes in the futures market conditions, are not readily available and are not easily created. Further, prior to late-2005 the historical gas cost forecasts utilized in the Company's quarterly gas cost filings typically provided only a 12-month forecast of gas costs; since late-2005 the Company has produced 24-month forecasts of gas costs on a quarterly basis. Thus the 18-month and 24-month commodity rates have been calculated from January 1, 2006 forward, based on a quarterly adjustment cycle, with rate changes effected when the recovery-to-cost ratio fell outside the 95% - 105% deadband range.

In determining the "FEI Rate – 18 Mth. Deferral" and the "FEI Rate – 24 Mth. Deferral" lines shown on the graph, the commodity recovery component of rates was changed as described above while the other components of rates (i.e. fixed basic charges, and variable delivery and midstream charges) were left unchanged.

**9. Reference: Exhibit B-1, Page 11**

> Figure 1 also highlights the challenge TGI has had with electricity competitiveness. On a variable, or commodity, cost basis, while TGI has remained competitive with electricity for high efficiency natural gas furnaces (relative to electric baseboards for space heating), TGI rates have only recently been below the 60% efficiency electric equivalent for hot water heating.

9.1 Does this mean that electric water heating is more efficient and cost effective?

**Response:**

The efficiency of an electric water heater at 90% efficiency is higher when compared to a 60% natural gas hot water heater. As shown in the referenced figure, this difference in efficiency is a significant contributor to the cost competiveness of gas water heater on a variable cost basis. As discussed in Section 4.4.5.2 of the Review Report, another challenge in terms of new or replacement water heaters is the difference in upfront cost to install new equipment. At current natural gas and electric prices, the consumer is relatively indifferent on a variable cost difference, but may chose electric heaters for new installations based on more cost effectiveness on a lifecycle basis, or if the consumer experiences actual or perceived gas costs increases or volatility.

9.2 Is this competitiveness issue caused by lost heat from a gas fueled water heating tank?

**Response:**

As discussed in the response to CEC IR1.1.9.1, the difference in efficiency is a major contributor to the competiveness of natural gas water heaters. The difference in efficiencies between an electric and gas water heater is attributed to how the water is heated. In an electric water heater, a copper coil is immersed in water and electric energy is converted to heat energy through resistance in the coil and in turn used to heat the water. In comparison, a natural gas water heater produces heat energy through gas combustion. Some heat is lost with the combustion by-products and vented to atmosphere, and the rest is used to heat the water.

9.3 If so what is happening to the heat and is FBU looking to control loss and or recover this heat?

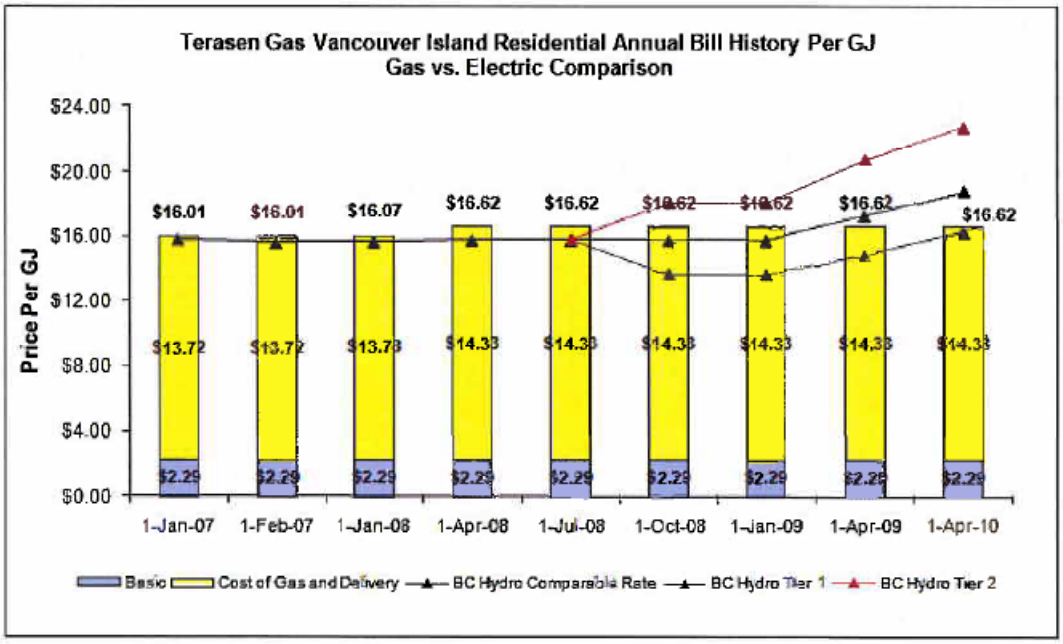
**Response:**

Please see response to CEC IR 1.1.9.2.

Currently, FBU has various incentive programs to encourage the use of more efficient gas-fired water heaters and boilers for the commercial sector through FBU's Energy and Efficiency Conservation group. Similar incentive programs for higher efficiency water heaters and boilers are being developed for the residential sector.

**10. Reference: Exhibit B-1, Page 12**

**Figure 2: TGVI's Historical Competitiveness to Electricity**




10.1 Please confirm that this recent improvement in competitiveness historically, is anticipated to continue improving because of substantial BC Hydro rate increases applied for and anticipated as likely, despite the fact that the BCUC may trim the requested increases during it regulatory process.

**Response:**

The reference figure compares residential rate equivalents for the FEVI service territory, which has a separate rate structure and has additional competiveness challenges due to a higher cost structure and the pending expiration of the royalty revenue arrangement between FEVI and the Province at the end of 2011. This is expected to result in significant rate pressures and increase the competitive challenge for FEVI in the future regardless of the movement of BC Hydro's rates or natural gas commodity rates.

In the FEI service territory, the current depressed gas prices have resulted in improved competiveness however there is considerable uncertainty with respect to commodity rates over the long term and therefore it cannot be concluded that competiveness will continue to improve in light of the future electric rate increases anticipated by BC Hydro. Future competiveness with

electric rates will depend on the relative changes in gas commodity and BC Hydro rates as well as other factors (such as the level of carbon taxes).

The Utilities have provided a comprehensive natural gas market review as part of the Review Report (Section 3 and Appendix D). There is good news - the development of shale gas has resulted in a significant increase in North America's long term supply potential. In other words, there appears to be lots of gas and the market is no longer relying on the development of LNG import facilities to meet future demand growth. As supported by the market review included in the Review Report, however, it is the Company's view that current natural gas commodity prices are not sustainable and that market rates and volatility will increase as supply and demand fundamentals come back into balance and as the full cost of the environmental mitigation and infrastructure development to support bringing new supply basins on stream becomes better understood.

10.2 Please confirm that this rate competitiveness change is structural, in terms of BC Hydro's cost of service drivers versus FBU cost of service drivers?

**Response:**

Please see the response to CEC IR1.10.1.

**11. Reference: Exhibit B-1, Page 13**

> Because of TGVI's greater competitive challenge, its past hedging program has been more extensive that TGI's. TGVI's most recent PRMP included a hedging horizon of five years, compared to three years for TGI, and targeted a higher percentage of hedgeable volumes.

11.1 Can FBU demonstrate quantitatively whether or not the longer term for hedging for TGVO was more or less successful in reducing price change than the shorter term hedging for TGI?

**Response:**

No, there is insufficient data to make any meaningful conclusions regarding the hedging horizons. Prior to 2009, the hedging horizon was three years for both FEI and FEVI. In mid 2009, FEVI (then called TGVI) applied to extend its planning horizon to 5 years in recognition that its long term competitive challenges were significantly higher than for the mainland utility, in particular as a result of the pending expiration of the royalty revenue arrangement between FEVI and the province. This proposal was accepted by the Commission pursuant to Letter L-45-09. In July 2010, pursuant to Commission Orders E-23-10 and E-24-10, the Utilities suspended all hedging activities.

**12. Reference: Exhibit B-1, Page 14**

> The management of gas costs and utilization of price risk management activities can be looked at from a business case perspective in creating value for customers. While the costs of managing gas supply and delivery to customers are passed onto customers via rates, natural gas utilities, including Terasen, have the responsibility for managing these costs. If Terasen is

12.1 Has FBU completed a business case analysis for its price risk management and if so could it please be provided?

**Response:**

As discussed in Section 2.7, the Review Report provides the business case for the management of gas costs and price risk management to create value for customers. The risks facing the Utilities and their customers have been identified in Section 4 of the Review Report in terms of managing commodity risks, rate and bill impacts and maintaining competitiveness. The alternatives available, such as the use of deferral account balances and rate adjustment mechanisms and use of storage, have been discussed in Sections 5 and 6, respectively. The recommendations aad proposed strategy to manage these risks are discussed in Sections 7 and 8 of the Review Report.

**13. Reference: Exhibit B-1, Page 16**

> However, natural gas prices in the future could be quite different than today. Reductions in natural gas drilling and decreased supply in response to low natural gas prices has already begun in some areas, as producers transition to drilling for oil and better returns on their investments. Increased industrial natural gas demand resulting from economic recovery is anticipated and there is evidence of this occurring already. Furthermore, natural gas demand for power generation is expected to rise significantly in the future as environmental legislation and aging coal plant retirements creates a shift from coal to gas fired generation. And, as always, weather events can significantly impact the short term supply and demand balance and cause prices to move adversely. So while prices are currently depressed relative to recent historical values, there is greater uncertainty in price levels and volatility going forward.

13.1 Please confirm that if there were structural cost pressures leading to increased price levels for natural gas that hedging would not be able to prevent these price increases from reaching the customers.

**Response:**

Please refer to responses to BCUC IRs 1.4.1.2 and 1.10.1.5.

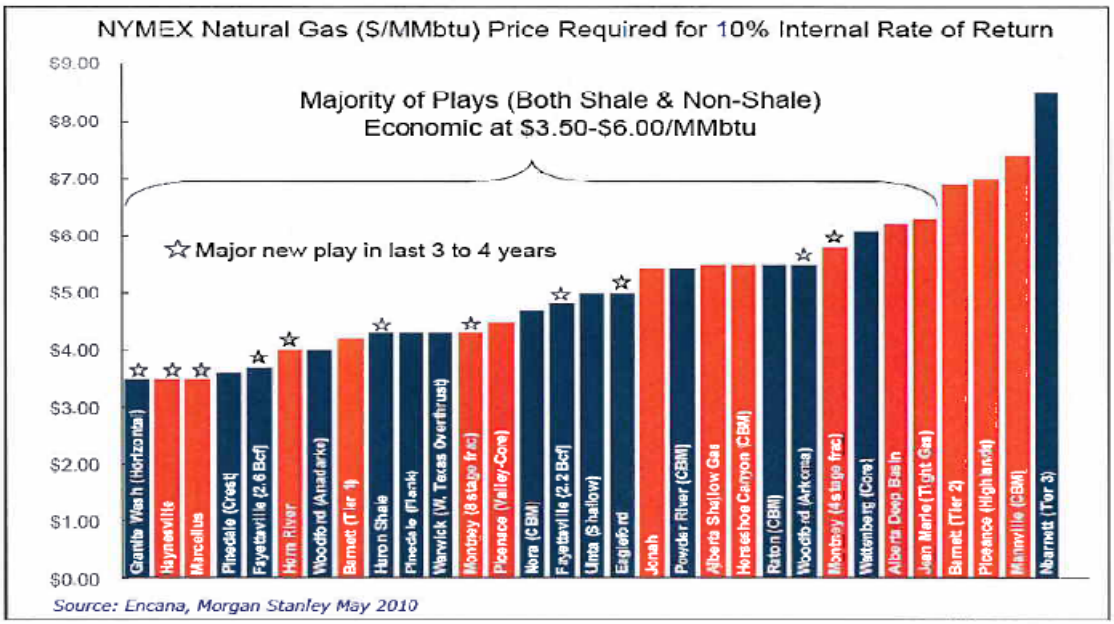
13.2 Can FBU identify whether it has any information to suggest that future price volatility or market price spikes will be any greater than in the past?

**Response:**

The Utilities do not have any information to suggest with any certainty that future market price volatility or market price spikes will be any greater or any less than in the past. However, the Utilities have provided a comprehensive review of natural gas markets as part of the Review Report (Section 7 and Appendix D) and as discussed in that review, recognise that there are numerous supply and demand variables that can impact market balances and adversely affect prices at any time. It is the Utilities position that it is prudent and appropriate to manage this price risk going forward in the best interests of its customers.

**14. Reference: Exhibit B-1, Figure 4**

**Figure 4: NYMEX Price Required for Various Gas Plays[4]**




14.1 Isn't this strong evidence of significantly increased structural price level competitiveness for natural gas?

**Response:**

The Utilities agree that the advent of shale gas is a major development for the North American natural gas industry, and represents a 'structural change" in terms of long term supply potential. However, as discussed in the Section 3 and Appendix D of the Review Report, there is still considerable uncertainty on the level of natural gas prices over the long term.

The reference figure represents the relative cost structures of the different shale and non gas plays across North America, and does show evidence that new plays are expected to be developed a lower cost than existing plays. However, unit production costs for producing natural gas are not always equal to market prices, particularly if natural gas demand increases faster than supply. It should be noted that in many regions the development of the natural gas production is in its infancy, and the full cost of meeting environmental challenges and infrastructure requirements is still uncertain. Furthermore, although the industry is experiencing significant increases in production from unconventional sources, these increases have mainly served to offset declines to maintain overall North American production levels, and in the long run the 'clearing price' will be influenced by the marginal cost of production.

As discussed in the response to CEC IR 1.10.2 other factors impacting competitiveness also include the carbon tax and capital cost differences. Furthermore, government policy and public perception regarding natural gas versus other sources of energy will also influence the Utilities' ability to attract and retain customers and maintain competitiveness. As such, the Utilities believe that currently low unit production costs for producers do not necessarily equate to price level competitiveness for natural gas as rate competitiveness is dependent on many other factors.

14.2 What is FBU's perspective on what these facts mean for BC Gas and for transmission supply to distant markets now having their own sources close at hand?

**Response:**

The Utilities have interpreted this question as asking the Utilities' opinion regarding the recent wide spread proximity of natural gas supplies to some markets and the affect on the Utilities.

The proximity of some shale gas developments to downstream markets, such as with the Marcellus shale in the eastern U.S., will contribute to declining contracting of long haul pipeline transportation capacity by end users and utilities. This has resulted in increases in tolls for some pipelines due to reduced throughput.. For example, the decrease in contracting of service on the TransCanada Pipelines Limited ("TCPL") mainline has significantly increased their tolls for remaining customers. The result of this for Alberta gas prices (i.e. AECO/NIT market hub) has been a widening basis relative to other market hubs (as discussed in Section 4.2 of Appendix D of the Review Report). As a purchaser of AECO/NIT gas, this is could be favourable for the Utilities provided that the price levels achieved by producers continue to be sufficient to encourage ongoing development to offset declines.

From a more regional perspective, the development of shale gas plays in north eastern B.C. has resulted in an increase in domestic supply available to downstream utilities such as the Utilities and other Pacific Northwest utilities. However, infrastructure developments are occurring in northern BC and Alberta which will absorb much of this incremental supply. Examples of this include TCPL's pipeline expansions in northern B.C. to move this gas into other markets, such as that related to oil sands demand to offset declining Alberta production and Kitimat liquefied

natural gas ("LNG") export facilities. Ultimately, this means that the Utilities need to continue to build and foster relationships with natural gas producers to encourage supplies of natural gas to the Utilities' service areas, and to ensure sufficient infrastructure is developed to avoid constraints and increase liquidity.

**15. Reference: Exhibit B-1, Page 19**

> The market price differential between crude oil and natural gas is also beginning to affect natural gas production. With crude oil prices well above historical averages and near $90 US per barrel and gas prices below recent historical averages, many producers are shifting their capital dollars from natural gas production toward more liquid rich gas and oil plays where returns on investment are much higher. This will certainly temper the growth in natural gas production and increase costs and provide support for higher natural gas prices in the future.

15.1 Has FBU examined whether or not it may be able to obtain long term natural gas contracts for supply, given the potentially extensive resource availability now?

**Response:**

The Companies currently have market priced long term contracts with key producers at indexed prices; however, it has not acquired any ownership stakes with producers for any of the producers' proprietary production. Almost all counterparties are unwilling to provide any physical supply at a fixed price and as a result the Companies must have a hedging program in place to swap out an indexed market price for a fixed price through the use of financial instruments. The Companies have not evaluated the viability of acquiring an ownership interest with a producer at the present time but may possibly explore this option in the future.

15.2 Would FBU consider long term contracts if they were available from producers?

**Response:**

Please refer to the response to CEC IR 1.15.1.

**16. Reference: Exhibit B-1, Page 19**

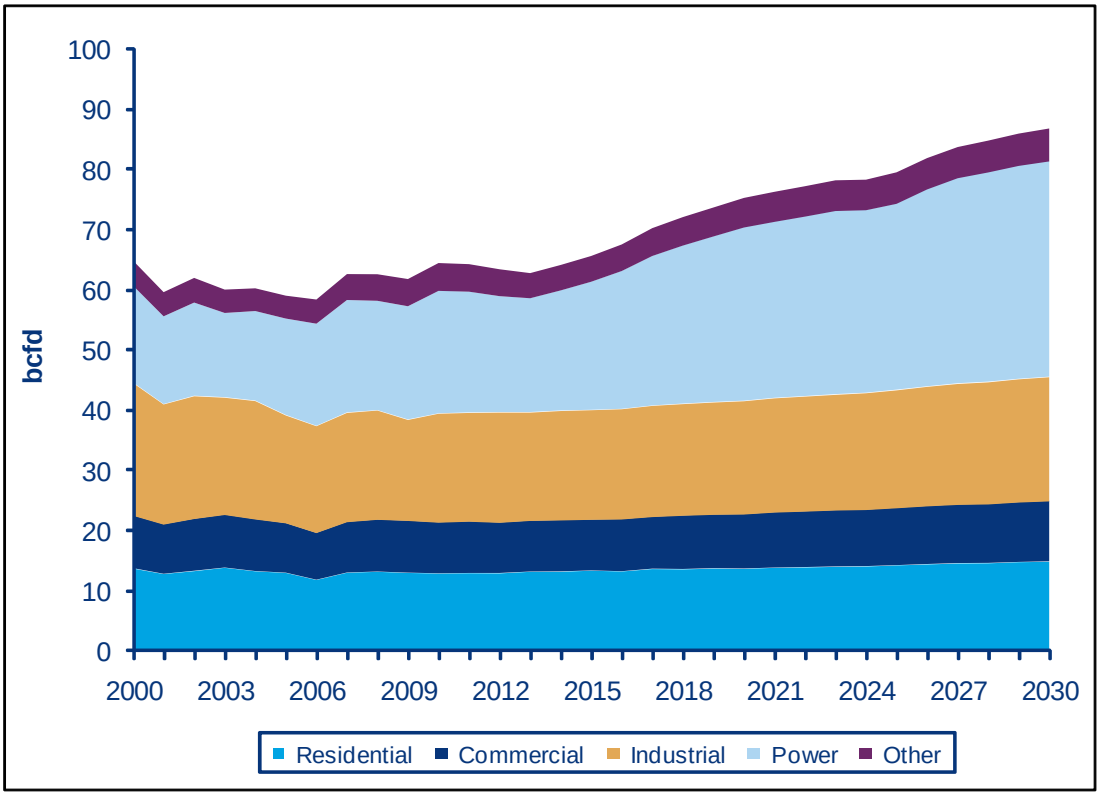
> Natural gas demand has also undergone dramatic changes in recent years. Commercial and, to a larger degree, industrial gas demand have been impacted and reduced due to the recent economic recession. However, economic growth in North America has returned in 2010 and continued growth is expected for the foreseeable future. With this economic growth, industrial demand is also expected to grow. Because industrial demand accounts for about a third of total natural gas consumption a recovery in this sector will provide support for natural gas prices in the future.

16.1 Please provide forecasts for when and how much of this demand for natural gas may return?

**Response:**

Figure 1 below displays the most current forecast available to the Companies regarding overall demand for natural gas from Wood Mackenzie's Natural Gas North American Long Term from September 2010. The figure depicts a material upward trend in overall demand, mainly fuelled by demand for power generation, for natural gas. This increase in demand coupled with expected declines in natural gas production is expected to put upward pressure on natural gas prices, as discussed in Section 3.3 of the Review Report. Additionally, please see Figure 5 of the Review Report for additional demand figures regarding overall natural gas demand.

**Figure 1: Forecasted Demand for Natural Gas (Bcf/d)**



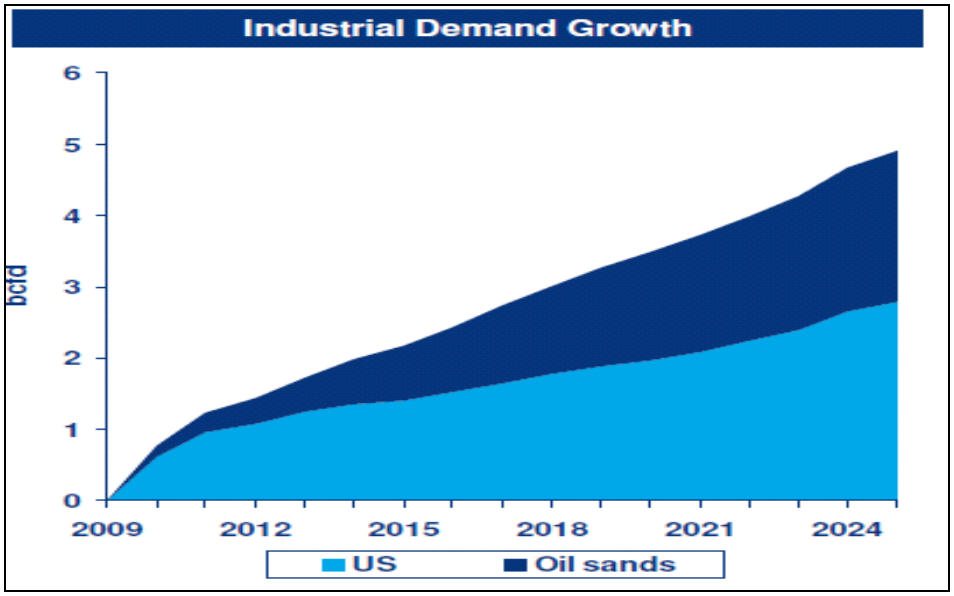

16.2 Does FBU anticipate in its forecasts that the move of industry and manufacturing to Asia will stop or will these changes continue?

**Response:**

The projections regarding recovery in natural gas demand, particularly industrial demand and as shown in the figure below, is obtained from Wood Mackenzie's report titled, "North America Long Term View" from September 2010. In its projections, Wood Mackenzie does not build in an explicit assumption regarding off-shoring of demand. However, Wood Mackenzie does indicate that the most influential industry for gas demand will be petrochemical production and once dormant and unutilized existing capacity that was mothballed in the 1998-2008 period will once again begin utilization. Presently, there is evidence of this already beginning to happen with several companies having announced intentions to restart production of existing ethylene,

methanol, and ammonia units. One example of recovering industrial demand is the restarting of Methanex's methanol plant in Medicine Hat, Alberta which will eventually amount to about 50,000 MMBtu per day of incremental natural gas demand.

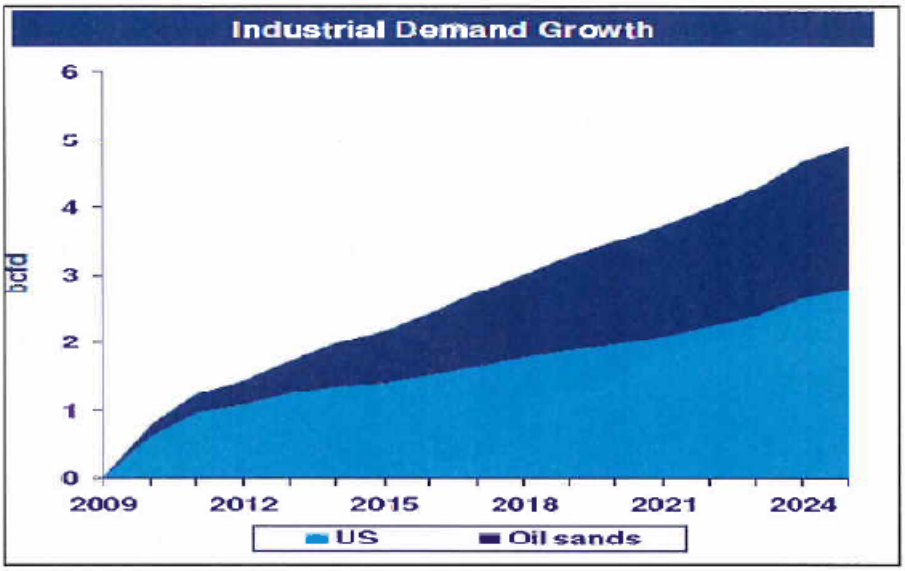
**Figure 1: Projected Industrial Demand Growth[2]**




[2] Wood MacKenzie North America Long Term View – September 2010

**17. Reference: Exhibit B-1, Page 20**

**Figure 5: Projected Industrial Demand Growth[5]**




It is expected that significant natural gas demand growth in the future will also come from power generation demand. In fact, natural gas demand for power generation is expected to be the largest source of growth in total natural gas demand. The main reasons for the increase in use of natural gas for power generation are the gradual phasing out of coal fired power generation plants and increased demand for electricity in general. Increased awareness of the harmful

17.1 What is the forecast for electrical demand in the US, is it rebounding significantly or is the slow economic growth, relative to past US economic performance, in the US expected to continue?

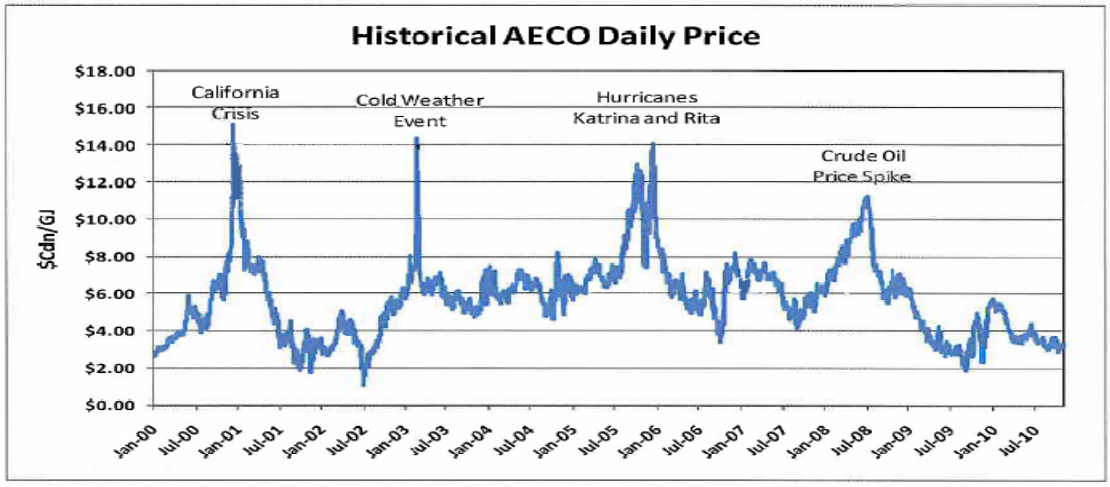
**Response:**

Electricity demand is expected to grow in the future in response to a growing economy and popularization of electricity-intensive applications such as electric vehicles. In return, this is expected to contribute positively to demand for natural gas as coal-fired electric generation plants are expected to be retired in response to stricter regulation regarding greenhouse gas emissions.

For more details, please refer to Section 3.1 and 3.3 of Appendix D of the Review Report.

**18. Reference: Exhibit B-1, Page 22**

**Figure 7: Historical AECO Prices**




18.1 It would appear that volatility is primarily driven by unknown, unknowable events affecting short term supply demand considerations, would FBU agree?

**Response:**

The Utilities do not wholly agree that market price volatility is primarily driven by unknown, unknowable events affecting short term supply and demand considerations. As Figure 7 on page 22 of the Review Report illustrates, market prices have been adversely impacted by some unknown events and also some known, but unpredictable, events. For example, the California energy crisis was arguable predicted by some but generally was not foreseen. Also, the crude oil price spike of 2008 was predicted by some as global spare capacity of oil supply was tight leading into the spike but many did not expect prices to soar to the levels that they did (and consequently cause natural gas prices to spike as well). However, the volatility caused by cold weather events and hurricane disruptions happens on a more frequent basis, although not always resulting in significant double digit price spikes. In fact, weather-related supply/demand disruptions are a common source of market price volatility as the degree of impact and timing of these events are hard to predict.

However, regardless of the causes of market price volatility, the Utilities believe that it is prudent, appropriate and expected by customers to reduce their exposure to this risk and rate impacts. The proposed hedging strategy is critical in this regard.

18.2 Does FBU have any information to suggest that the source of volatility will be substantially different from these past patterns?

**Response:**

The Utilities do not have any information to suggest that the source of volatility will be substantially different from these past patterns. However, as discussed in the response to CEC IR 1.18.1, Utilities believe that it is prudent, appropriate and expected by customers to reduce their exposure to this volatility, regardless of its source.

**19. Reference: Exhibit B-1, Page 23**

> occurred. Now, coal prices are providing the next level of support for gas prices. This fuel switching ability in the U.S. is estimated to be in the order of up to about 4.5 Bcf/d depending on the differential between coal and gas prices. As a result in the recent low price environment resulting from abundant supply, this incremental demand for natural gas from coal substitution provides support, or a soft floor, for natural gas prices. This coal price support is reflected in the following figure, with recent historical and forward natural gas prices trading near coal prices.

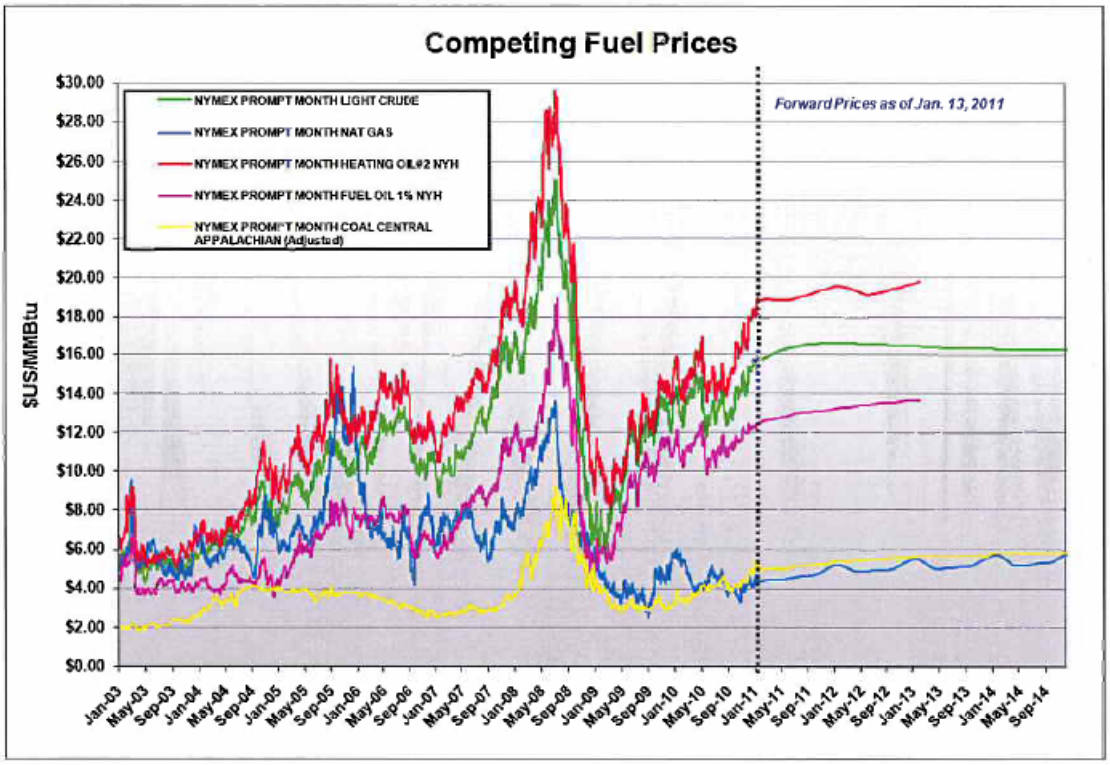
19.1 This proposed disconnection from oil and potential connection with coal pricing seems like a structural price level consideration not a volatility situation, would FBU agree?

**Response:**

It is assumed the question is asking if there has there is a permanent change in the fundamentals (i.e: "structural price level" consideration) that drive natural gas prices that impacts volatility. As discussed in the referenced paragraph, natural gas price's relationship with oil and coal prices has been primarily driven by fuel switching capacity. In the past, residual fuel oil prices supported natural gas prices as some power generators could switch between these fuels. In today's depressed natural gas price environment, in particular when compared to oil prices, any oil based fuel switching that can occur in this timeframe has already occurred, and the next significant fuel switching volumes are associated with coal generation. However, as discussed in Appendix D of the Review Report, fundamentals continue to point to the strong possibility of upward pressure on natural gas prices in the future. Demand, mainly from industrial and electric generation, is expected to begin recovering in response to improved economic conditions while at the same time production is beginning to show signs of slowing in response to continued weakness in gas prices. Additionally, with various governmental environmental initiatives aimed at reducing greenhouse gas emissions, coal fired electric plants are expected to begin retiring at a greater pace than in the past and be replaced by natural gas fired power generation. As demand and supply balance tightens, there is the potential for natural gas prices to reconnect with oil prices and the markets will experience increased volatility.

**20. Reference: Exhibit B-1, Page 24**

Figure 8: Competing Fuels Prices



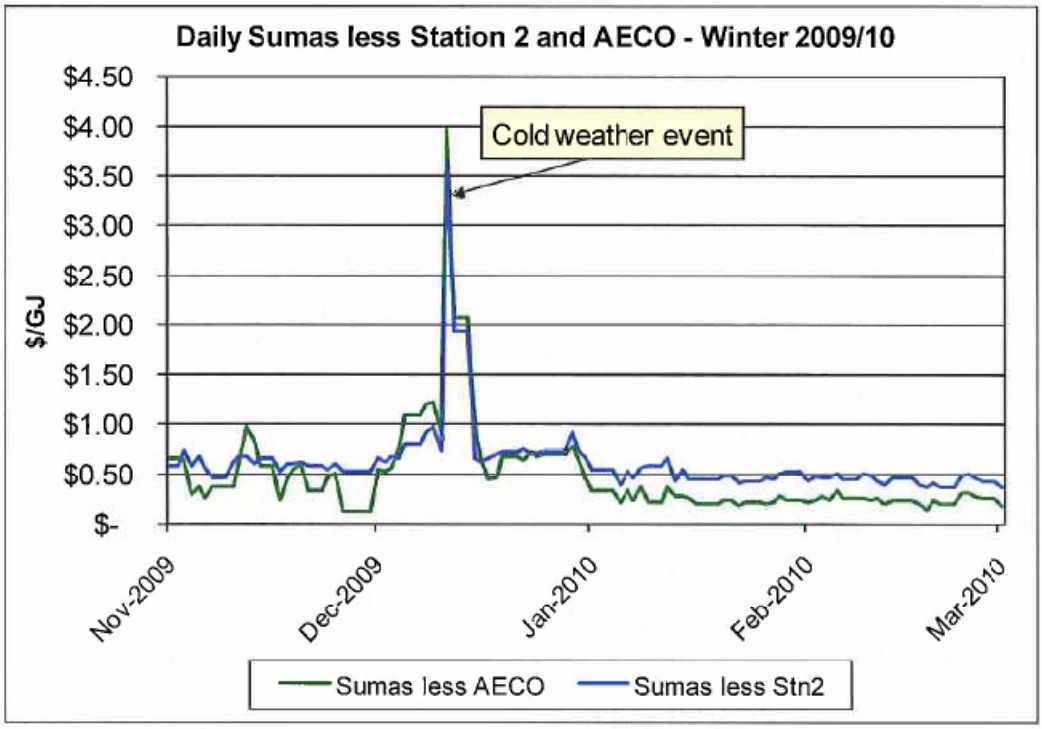

20.1 With market forward prices showing up between about $5 to $6 per GJ, given the new costs of production would it not be reasonable to expect that producers will find this an acceptable price to continue development and production?

**Response:**

Not necessarily, there are too many variables to make this assumption. First of all, this would require an assumption the producers can continue to manage the costs of production, environmental protection and the infrastructure required to connect to markets, and also provide an appropriate level of return on their investment. More importantly, it also assumes that there is no competition for capital between development opportunities available to these producers. For example, currently industry participants are witnessing a significant shift from natural gas development to more liquid plays in response to high oil prices.

**21. Reference: Exhibit B-1, Page 26**

**Figure 10: Sumas less Station 2 and AECO Prices - Winter 09/10**

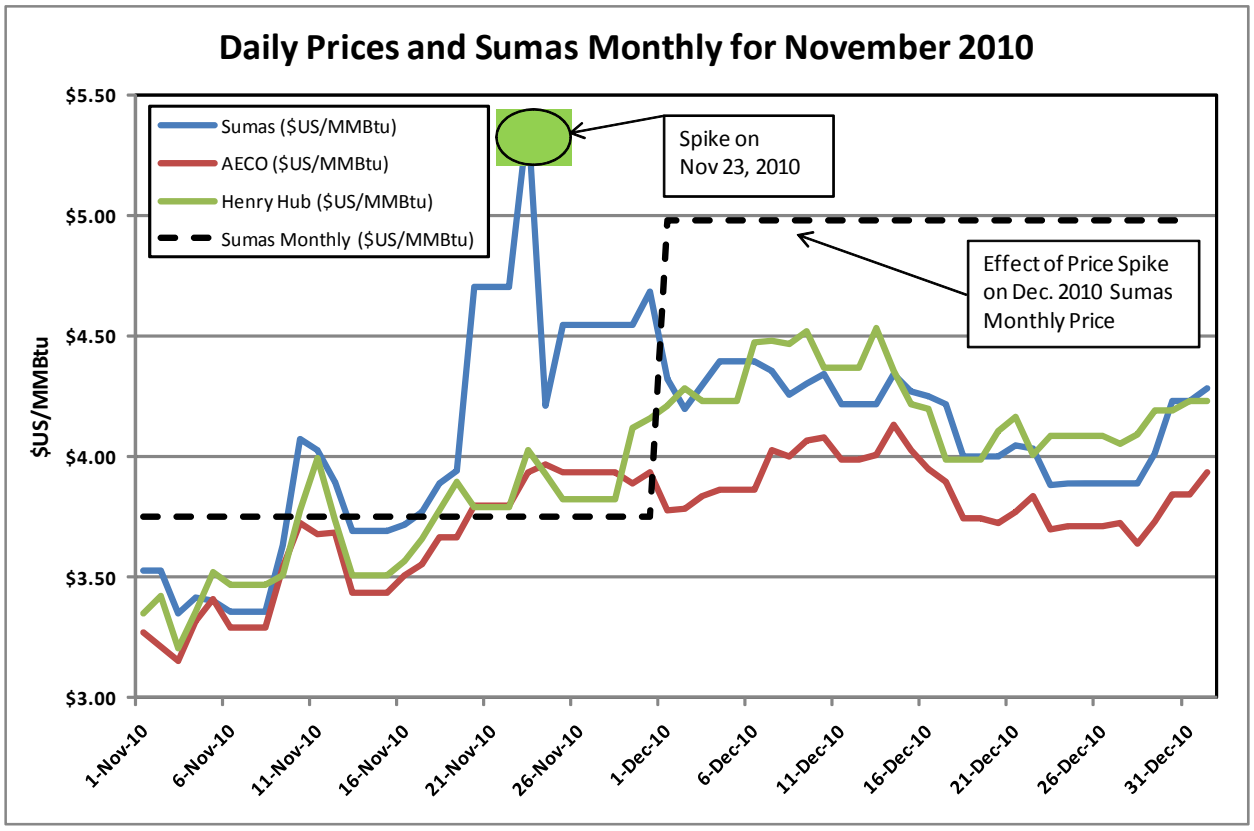



21.1 Is this not further direct evidence that the real issues are volatility due to short term supply demand imbalance perceived by the market?

**Response:**

Regional price disconnections are an example of the volatility created by short term supply and demand imbalances, whether perceived or real. These price disconnections directly impact short term market spot prices but they can also impact the subsequent month's pricing as well. As the following graph in Figure 1 illustrates, the November 2010 Sumas price spike caused the December monthly Sumas price to be significantly higher than both spot Sumas prices and other regional monthly prices.

**Figure 1: Sumas Price Spike and December Monthly Price**




Without effective price risk management, this volatility could adversely impact customer rates and competitiveness, whether perceived or real. As such, market price volatility reduction and maintaining competitiveness are important objectives of the hedging program.

**22. Reference: Exhibit B-1, Page 27**

> While the development of the prolific Horn River and Montney unconventional gas plays in northeast B.C. will significantly add to the region's supply of natural gas, the full potential of these plays will only be realized if the infrastructure is available to connect these supplies to markets outside of B.C. For example, the TransCanada Pipeline Limited ("TCPL") Horn River and Groundbirch pipeline projects will provide producers an avenue to transport Horn River and Montney supply on to TCPL's Alberta system, to offset declines in Alberta conventional supplies and feed the oil sands demand, and eastern markets. Up to 0.7 Bcf/d (initially) of north eastern B.C. supply could also flow to the Kitimat LNG facility to be processed and exported to Asia to meet growing demand. Therefore, the development of these unconventional plays in northeastern B.C. is not expected to reduce the risk of significant price disconnections within the region.

22.1 Would FBU not agree that if there were a significant price disconnection it would be a price level change, with which hedging could not deal and customers would have to deal with the new price?

**Response:**

No. Significant regional price disconnections occur when regional infrastructure, such as pipeline capacity or storage deliverability, becomes constrained by the increased demand in the region. In the Pacific Northwest, this typically occurs at the Sumas market hub during periods of high winter demand. Please also see the response to BCOAPO IR 1.11.2 regarding the frequency of Sumas price disconnects.

The degree to which this temporary price disconnection develops into a price level change will depend on regional infrastructure developments and the balance of future supply and demand in the region. Often, the spot price disconnection can impact the following month's price, as discussed in the response to CEC IR 1.21.1, particularly if cold weather has occurred early in the winter and significant storage capacity has been drawn down.

As discussed in Section 8.4 of the Review Report, the Utilities, and RiskCentrix, believe that basis swaps are the appropriate hedging instruments for mitigating the impacts of these regional price disconnections.

**23. Reference: Exhibit B-1, Page 28**

> The hedging programs of the natural gas utilities in the other major Canadian jurisdictions are discussed in this section. For those utilities that do employ hedging, the objectives of their hedging programs are consistent with Terasen in terms of managing market price volatility and, for some, competitiveness. For those that do not employ hedging, they use other methods to manage price volatility and gas costs.

23.1 For those utilities that do not hedge, what other methods do they use to manage price volatility?

**Response:**

Section 4.1.1 of the Review Report discusses the methods of mitigating price risk which the other major Canadian utilities employ. While SaskEnergy Incorporated ("SaskEnergy"), Gaz Metro Limited Partnership ("Gaz Metro") and Manitoba Hydro use hedging, the other major utilities in Ontario and Alberta use other methods to manage price risk for customers. . Manitoba Hydro is currently able to offer fixed rate offerings to natural gas customers, providing an alternative to the fixed rate offerings of marketers, and does use hedging to support the fixed rate offering. As such, Manitoba Hydro was directed by its regulator to cease all hedging for its variable rate standard offering for terms after July 2011.

In Ontario, Union Gas Limited ("Union") and Enbridge Gas Distribution Incorporated ("Enbridge") had their hedging programs effectively cancelled by their regulator in 2008 and 2007, respectively. To help with mitigating price risk, these two utilities have significant amounts of contracted storage capacity and access to the liquid Dawn market hub which reduces their need to purchase seasonal and peaking gas and take advantage of favourable priced spot gas when load requirements dictate. The large quantity of available storage capacity in Ontario is in stark contrast to the situation the Companies face in British Columbia. Storage capacity relative to overall demand in the Pacific Northwest ("PNW") region is relatively scarce and the Companies do not have the same access to storage resources as utilities have in Ontario. As a result, this can have adverse impacts on prices in the PNW region, particularly at Station 2 and Sumas during periods of high demand typically seen during colder winter months.

For natural gas customers in Alberta, until this past winter, the government of Alberta provided customers with a rebate whenever monthly natural gas rates exceeded $5.50/GJ. This effectively insulated natural gas customers from significant amounts of market price volatility. However, with the impacts of the recent recession affecting government revenues, this rebate program was cancelled. Critics of the government rebate claim that it did not provide natural gas customers with appropriate market price signals and therefore did not promote energy conservation. Currently, in the absence of the rebate and Alberta utilities' lack of any hedging

program, customers are fully exposed to market prices. Natural gas rates in Alberta are adjusted on a monthly basis.

23.2 Does FBU have a comparative quantitative performance analysis for those that do use hedging and those that do not and if so could that be provided?

**Response:**

No, FBU does not have a comparative quantitative performance analysis for those other utilities that do use hedging and those that do not. The information provided in Section 4.1.1 of the Review Report regarding the other utilities is primarily based upon conversations with those utilities. FBU is not privy to the details of the performance of the hedging programs of other utilities. Furthermore, given the unique characteristics of each of the utilities' operating environment, natural gas marketplace and competitive challenges, FBU believes that a true comparative analysis would be difficult.

**24. Reference: Exhibit B-1, Page 29**

> Manitoba Hydro is another utility that manages rate volatility for customers. However, Manitoba Hydro does this primarily through fixed rate offerings for customers. Beginning in 2009, Manitoba Hydro began providing fixed price offerings to residential and commercial customers for one, three and five year terms. Therefore, those customers that desire stability in rates can choose to purchase their commodity supply from Manitoba Hydro or marketers. As such,

24.1 Is the Customer Choice program a source of fixed price stability for customers seeking to avoid price volatility?

**Response:**

Yes, the Customer Choice program is one option for customers seeking commodity price assurance and 100% price certainty. Please see the responses to BCUC IRs 1.4.1.5, 1.13.1.2 and 1.7.1.4 for further discussion on customers' willingness to participate in the Customer Choice program in order to obtain price stability.

24.2 Is it necessary to do more than offer a choice in order to minimize customer fuel switching in response to unforeseen price spikes and comparative fuel use perceptions?

**Response:**

Yes, it is the view of the Utilities that the Customer Choice program does not fully address the competitive risks that could prompt customer migration to other energy sources, and therefore it is necessary to do more. Although the Customer Choice can offer rate stability, it does so at a cost to customers, which over the long run could decrease competitiveness. In addition, as discussed in the responses to BCUC IRs 1.7.1.4 and 1.13.1.1 the majority of customers do not participate in the Customer Choice program. The inability to maintain competiveness and subsequent migration of customers to other sources of energy impacts all remaining natural gas consumers through higher delivery rates, regardless if they receive their commodity supply through marketers or from the Utilities' variable rate offering.

**25. Reference: Exhibit B-1, Page 30**

> The primary natural gas utilities in Ontario had hedging programs in the past but do not currently. Union Gas Limited ("Union Gas") and Enbridge Gas Distribution Inc. ("Enbridge") effectively had their hedging programs cancelled in 2008 and 2007, respectively. While these utilities maintained that their risk management activities had provided a material reduction in rate volatility for customers at a minimal cost, the Ontario Energy Board ("OEB") disagreed and argued that the quarterly rate adjustment mechanism process and the equal billing plan provided sufficient rate smoothing effects. Terasen strongly disagrees with this assertion and argues that the quarterly rate adjustment mechanism process and the equal billing plan do not provide the same degree of rate volatility mitigation as an effective hedging program, whether in Ontario or B.C. This is discussed in Sections 4.5.1 and 5.1. It is important to note that, with

25.1 Please provide a quantitative analysis of what each of the possible strategies for price volatility management can do to smooth out commodity prices and what is an appropriate cost per customer to ascribe to each of the methods?

**Response:**

Please refer to the responses to BCOAPO IRs 1.2.1, 1.2.2, 1.2.4, 1.8.1, and 1.9.3.

25.2 Apart from strong disagreement does FBU have strong quantitative evidence as to what each component of its proposed hedging program can add in value over what the other methods can add?

**Response:**

Please refer to the responses to CEC IR 1.25.1, and BCOAPO IRs 1.2.2 and 1.2.4.

**26. Reference: Exhibit B-1, Page 31**

> and gas costs and their effects on rates in terms of variability and competitiveness. If Terasen is able to effectively manage these costs then value is provided to customers through reasonable, relatively stable rates that are competitive with other sources of energy. This same principle applies to Terasen's price risk management and underlies its importance in maintaining and growing customer base to the benefit of all customers.

26.1 Would FBU agree that the FBU price management and price risk management can only add to providing price stability and cannot deal with longer term structural price competitiveness issues?

**Response:**

The Utilities agree that in the long term, if fundamentals were to permanently drive natural gas costs above the competitive thresholds, that the hedging strategy would then really only be able to address price stability concerns. Please also see the response to BCUC IR 1.4.1.2.

**27. Reference: Exhibit B-1, Page 32**

> Maintaining competitiveness with other sources of energy enables Terasen to grow its customer base and continue to provide reasonable rates for customers. This will become increasing important in the future as energy consumers in B.C. have greater options for their energy sources. Ground source heat pumps and air source heat pumps are two examples of new energy sources that are growing in popularity. However, with these emerging energy alternatives being in their early stages of growth in B.C., Terasen's primary competitive challenge at this time continues to be electricity. As discussed in the next section, maintaining competitiveness with electricity is not only in the best interests of Terasen's customers, but it is also in the best interests of electricity consumers in the province.

27.1 Isn't it true that this form of technological competition from other fuel sources is really a structural price issues, with which the FBU price risk management or hedging cannot deal?

**Response:**

The Utilities price risk management and hedging program mitigate natural gas price volatility and help maintain competitiveness over the short term with other sources of energy, whether it is electricity or air source heat pumps. In the short term, competitiveness with other sources of energy will depend on numerous factors including the prices or rates of other sources of energy, the volatility of market gas prices, capital cost differences, and the carbon tax on natural gas.

However, as discussed in the response to BCUC IR 1.4.1.2, over the long run, the energy marketplace will determine the competitiveness of natural gas. Government policy and public perception towards energy and the role of natural gas in B.C. will be critically important in this regard.

**28. Reference: Exhibit B-1, Page 34**

**Table 1: Estimated Annual TGI Bill Impacts Resulting from Load Migration**

| TGI Delivery Rate Impact of Reduced Load by 22 PJs | Rate 1 | | Rate 2 | | Rate 3 | |
|---|---|---|---|---|---|---|
| | Loss of Customers & Load | Loss of Load Only | Loss of Customers & Load | Loss of Load Only | Loss of Customers & Load | Loss of Load Only |
| Basic Charge & Delivery Rate Increase (%) | 17% | 12% | 17% | 12% | 17% | 12% |
| Approximate Annual Bill Impact ($) | $ 78 | $ 55 | $ 192 | $ 135 | $ 1,398 | $ 983 |

28.1 What would the comparable bill impact be in terms of today's bills and commodity rates for these scenarios?

**Response:**

Please refer to the revised table below which now includes an average Lower Mainland customer's annual bill for each of Rate Schedules 1 – 3 based on current commodity rates and including rate riders.

Assuming loss of load and customers, the impact to the annual bill is approximately an 8% increase for a Rate Schedule 1 customer, a 7% increase for a Rate Schedule 2 customer, and a 6% increase for a Rate Schedule 3 customer. Assuming loss of load only, the impact to the annual bill is approximately a 5% increase for Rate Schedules 1 and 2 customers and a 4% increase for a Rate Schedule 3 customer.

**Table 1: Estimated Annual FEI Bill Impact Resulting from Load Migration**

| Table 1: Estimated Annual TGI Bill Impacts Resulting from Load Migration | | | | | | |
|---|---|---|---|---|---|---|
| TGI Delivery Rate Impact of Reduced Load by 22 PJs | Rate 1 | | Rate 2 | | Rate 3 | |
| | Loss of Customers & Load | Loss of Load Only | Loss of Customers & Load | Loss of Load Only | Loss of Customers & Load | Loss of Load Only |
| Basic Charge & Delivery Rate Increase (%) | 17% | 12% | 17% | 12% | 17% | 12% |
| Approximate Annual Bill Impact ($) | $ 78 | $ 55 | $ 192 | $ 135 | $ 1,398 | $ 983 |
| Current Average Annual Bill | $ 1,009 | $ 1,009 | $ 2,864 | $ 2,864 | $ 23,587 | $ 23,587 |
| Approximate Increase to Annual Bill (%) | 8% | 5% | 7% | 5% | 6% | 4% |

**29. Reference: Exhibit B-1, Page 35**

province. On the other hand, the carbon tax, introduced in 2008, is applicable to natural gas and not electricity and increases each year until 2012 after which time there is uncertainty regarding the amount. Not only does this tax effectively add a cost to natural gas rates but also adversely influences public perception regarding the use of natural gas relative to other sources of energy. This serves to increase the challenge for natural gas competitiveness in the future. increasing electricity rates going forward. The extent of these rate increases will depend on the magnitude, cost and timing of infrastructure additions, the cost of additional supply resources, the rate increases approved by the Commission and the rate structures utilized to encourage

29.1 Since the inception of the Carbon Tax has the commodity cost of natural gas plus the Carbon Tax increased or decreased on average?

**Response:**

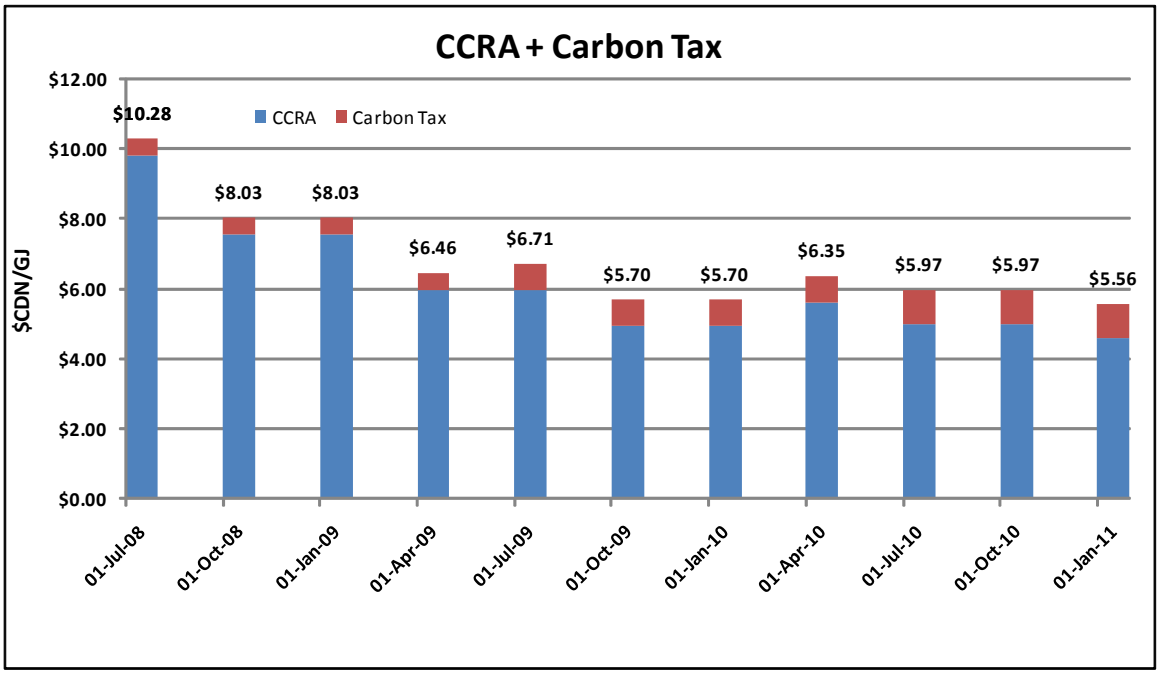
The Carbon Tax was introduced on July 1, 2008 equivalent to about $0.50/GJ and increasing by about $0.25/GJ each July to 2012 when it is expected to reach approximately $1.50/GJ.

The level of the Carbon Tax after July 2012 is uncertain at this point in time. Some industry experts have indicated that for any carbon policy to be effective in reducing carbon emissions, carbon should be priced at approximately ten times its current amount.[3]

Figure 1 below illustrates the Carbon Tax and the Commodity Cost Reconciliation Account ("CCRA") rate from July 2008 to January 2011. So, in general the combination of the CCRA and the Carbon Tax have result on declining gas costs to customer over this timeframe.

[3] Vancouver Sun; February 23 2011, Marc Lee.

**Figure 1: Carbon Tax plus CCRA Rate**



**30. Reference: Exhibit B-1, Page 41**

Table 3: **Projected Residential Electricity Rate Increases**

| | F2011 | F2012 | F2013 | F2014 | F2015 |
|---|---|---|---|---|---|
| Projected Rate Increase | 4.67% | 17.44% | 5.42% | 9.72% | 8.37% |
| Projected Deferral Account Rate Rider | 3.53% | 2.50% | 2.20% | 2.00% | 1.70% |
| Projected Net Bill Impact | 7.29% | 16.27% | 5.11% | 9.51% | 8.05% |
| Projected Cumulative Net Bill Impact | 7% | 25% | 31% | 44% | 55% |

30.1 Please provide for the record the BC Hydro applied for price increases for each of the forward years?

**Response:**

The updated version of BC Hydro's applied-for rate increases is found in Table 2-2 at Page 2-2 of BC Hydro's F2012 – F2014 Revenue Requirement Application. Table 2-2 is included below.

**Table 2–2 Rate Increase Forecast**

| | Approved | Plan | | | Forecast |
|---|---|---|---|---|---|
| (%) | F2011 | F2012 | F2013 | F2014 | F2015 |
| Rate Increase | 6.11 | 9.73 | 9.73 | 9.73 | 6.95 |
| Credit per NSA (January to March 2011) | (4.71) | 0.00 | 0.00 | 0.00 | 0.00 |
| Rate Rider | 3.53 | 2.50 | 2.50 | 2.50 | 2.50 |
| Net Annual Bill Impact | 7.29 | 10.13 | 9.73 | 9.73 | 6.95 |
| Cumulative Bill Impact | 7.29 | 18.16 | 29.66 | 42.28 | 52.17 |

Note: The presentation of the information above is consistent with the F11 RRA NSA Provision 9(xv).

**31. Reference: Exhibit B-1, Page 42**

Table 4: Historical BC Hydro Requested vs. Approved Rate Increases

| Rate Application | Fiscal Year | BC Hydro Rate Increases | | |
|---|---|---|---|---|
| | | Applied For | Approved | Test Period Cumulative Difference |
| F05/F06 RRA | F2005 | 7.23% | 4.85% | -4.5% |
| | F2006 | 2.00% | 0.00% | |
| F07/F08 RRA | F2007* | 4.65% | 1.54% | -4.7% |
| | F2008 | 2.71% | 0.11% | |
| F09/F10 RRA | F2009 | 6.56% | 2.34% | -4.0% |
| | F2010 | 8.21% | 8.74% | |
| F11 RRA | F2011** | 9.26% | 7.29% | -2.0% |

*The F2007 increase occurred on July 1 and was therefore for a partial year
**F2011 increases include both the permanent rate increase and the rate rider change

31.1 Please provide a similar analysis for the Terasen Gas Inc applied for and approved rate increases for the same time period?

**Response:**

The table below summarizes the historical rate changes for FEI Lower Mainland residential customers. The fixed basic monthly, and the variable delivery and midstream components of rates are typically set annually with a January 1 effective date, while the commodity recovery charges are subject to quarterly review and resetting.

**Historical FEI Requested versus Approved Rate Changes**

| Rate Application | Fiscal Year | FortisBC Rate Increase | | |
|---|---|---|---|---|
| | | Applied For | Approved | Difference (in %) |
| F05/F09 PBR and Quarterly Gas Cost Reviews | 2005, Jan 1 | -0.53% | -0.53% | |
| | Apr 1 | | | |
| | Jul 1 | 5.61% | 5.61% | |
| | Oct 1 | 13.28% | 13.28% | |
| | 2006, Jan 1 | -0.39% | -0.39% | |
| | Apr 1 | -11.70% | -11.70% | |
| | Jul 1 | | | |
| | Oct 1 | | | |
| | 2007, Jan 1 | 1.88% | 1.88% | |
| | Apr 1 | | | |
| | Jul 1 | | | |
| | Oct 1 | -5.89% | -5.89% | |
| | 2008, Jan 1 | 3.94% | 3.94% | |
| | Apr 1 | 10.97% | 10.97% | |
| | Jul 1 | 11.01% | 11.01% | |
| | Oct 1 | -13.64% | -13.64% | |
| | 2009, Jan 1 | -0.66% | -0.66% | |
| | Apr 1 | -12.73% | -12.73% | |
| | Jul 1 | | | |
| | Oct 1 | -8.95% | -8.95% | |
| F010/F11 RRA and Quarterly Gas Cost Reviews | 2010, Jan 1 | 11.26% | 10.33% | -0.9% |
| | Apr 1 | 5.80% | 5.80% | |
| | Jul 1 | -5.29% | -5.29% | |
| | Oct 1 | | | |
| | 2011, Jan 1 | -5.83% | -6.37% | -0.5% |

31.2 Would FBU agree that even if the BC Hydro rate increases applied for were reduced by 2% per year from what has been applied for the level of price competitiveness for the FBU would continue to improve significantly?

**Response:**

The Companies have provided an extensive analysis of BC Hydro projected rate increases equal to 100% and 50% of the forecast amounts presented in the BC Hydro F2011 RRA Settlement Agreement, shown in the figure below. Rate increases that are 2% below the forecast increases would fall between the 100% and 50% increase lines although closer to the 100% line than the 50% line. Observations about competitiveness in the space and water heating end use markets would therefore be similar to those presented for the 100% increase case.

**Table 3: Projected Residential Electricity Rate Increases**

| | F2011 | F2012 | F2013 | F2014 | F2015 |
|---|---|---|---|---|---|
| Projected Rate Increase | 4.67% | 17.44% | 5.42% | 9.72% | 8.37% |
| Projected Deferral Account Rate Rider | 3.53% | 2.50% | 2.20% | 2.00% | 1.70% |
| Projected Net Bill Impact | 7.29% | 16.27% | 5.11% | 9.51% | 8.05% |
| Projected Cumulative Net Bill Impact | 7% | 25% | 31% | 44% | 55% |

Although, currently FEI is competitive with electric rates on a variable cost basis absent of any consideration of upfront capital cost expenditures with upgrading or switching to natural gas space heating, when variables such as capital cost differentials, carbon tax policy, natural gas market price volatility, and public perception and governmental policy are considered this significantly reduces FEI's competitive position relative to electricity. Furthermore, FEI is more challenged with water heating load due to the relatively lower efficiency of water heaters. FEVI is even more challenged than FEI with its higher delivery costs. Future changes in electricity rate structures also hold the potential to influence the competitive position of natural gas. The recent BCUC Decision on BC Hydro's RIB Re-pricing Application establishes a pricing approach for only three years. Time-of-use rate structures that will be established after smart electric metering is installed may offer the opportunity to consumers to manage their energy costs for specific end uses in a way that increases the competitive challenge faced by natural gas.

Please refer to Section 4.4.3.2 of the Review Report and figures 13, 14, 15, and 16 which show, what the Companies believe, is a reasonable range of estimates for future electricity rate increases for BC Hydro and the competitive position of natural gas in the space and water heating markets.

**32. Reference: Exhibit B-1, Page 42**

> The first graph for each application includes BC Hydro's projected rate increases, including projected rate riders. The second graph includes only 50% of BC Hydro's projected rate increases but 100% of the projected rate riders given the significant deferral balance deficit to be recovered from customers. The AECO forward price curve and potential range (based on

32.1 Does FBU have any evidence that a 50% reduction in BC Hydro applied for rates is realistic?

**Response:** No, the Utilities do not have any evidence that supports a 50% reduction in BC Hydro's proposed rate increases. As discussed in Section 4.4.3.2 of the Review Report, the 50% reduction in BC Hydro's forecast of future rate increases was simply used to form the bottom end of a reasonable range of possible outcomes to be used in assessing future competiveness. In other words, although the Utilities cannot predict BC Hydro's final approved rate increases, given the cost pressures faced by BC Hydro, it is not expected that it would be less than 50% of BC Hydro's current forecasts. Likewise, it is expected that given the current public and political scrutiny on future rate increases, the potential for policy change and the regulatory oversight of any rate increase requests, it is not expected that final rate increases will exceed 100% of BC Hydro's current forecasts.

32.2 Does FBU agree that even if the rate increase for BC Hydro were ½ the competitive spread over the natural gas rates would continue to improve for FBU?

**Response:**

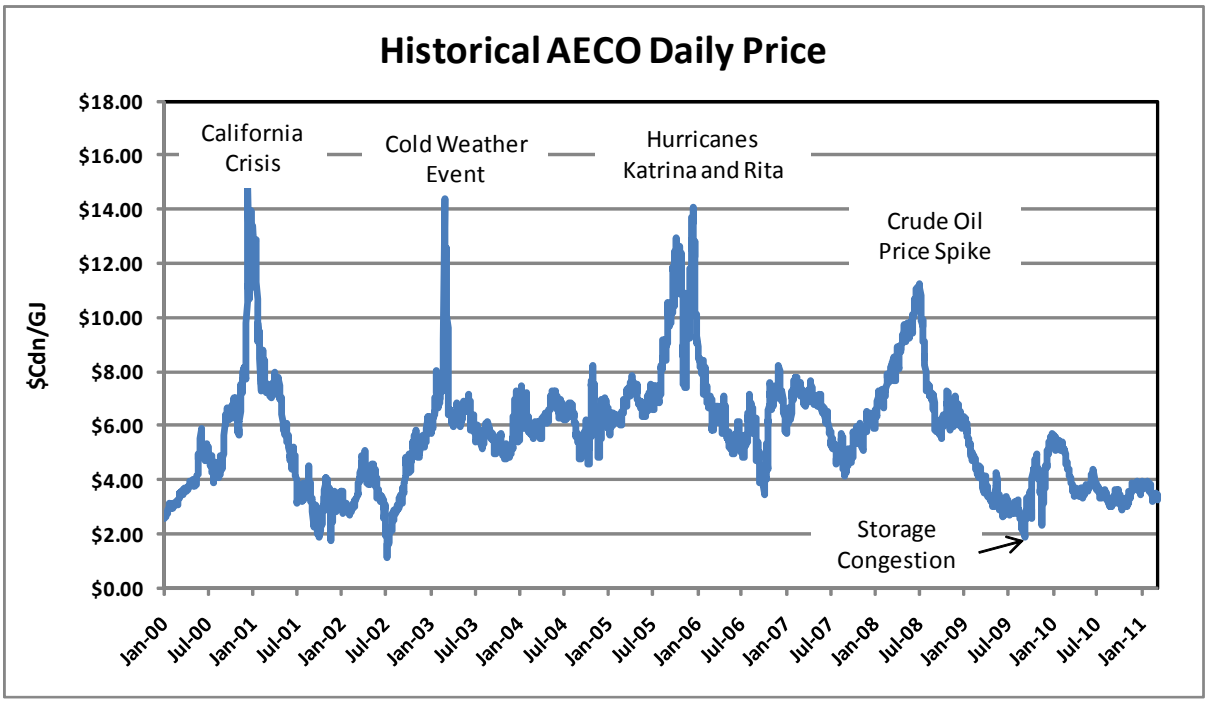
Please refer to the response to CEC IR 1.31.2.

The current competitive advantage of natural gas for space heating would only be true if natural gas prices remained at their current historically low level. As discussed in Section 2 and 3 of Appendix D of the Review Report, fundamentals point to upward bullish pressure on natural gas prices as a result of recovering demand, mainly from industrial customers and a recovering economy, and a slowdown in natural gas production.

As illustrated in figure 1 below, natural gas prices have rarely shown any stability at any price level and have exhibited tremendous amounts of volatility in the past. To assume that current natural gas prices will remain at their historically low level and if this past amount of volatility is

experienced again in the market place in the future, this will significantly challenge FEI's ability to compete effectively with electric rates.

**Figure 1: Historical Volatility in AECO Daily Price**




At present price levels, FEI is already competitively challenged with respect to hot water heating due the relative lower efficiency of natural gas hot water heaters relative to electric hot water heaters. Please refer to Section 3.4.5.4 of the Review Report for an extensive analysis of competitiveness with hot water and space heating applications. Additionally, please refer to figures 2 and 3 below for competiveness of natural gas with hot water heating applications.

**Figure 2: TGI Electric Equivalent for Hot Water Heating with BC Hydro Projected Rate Increases**

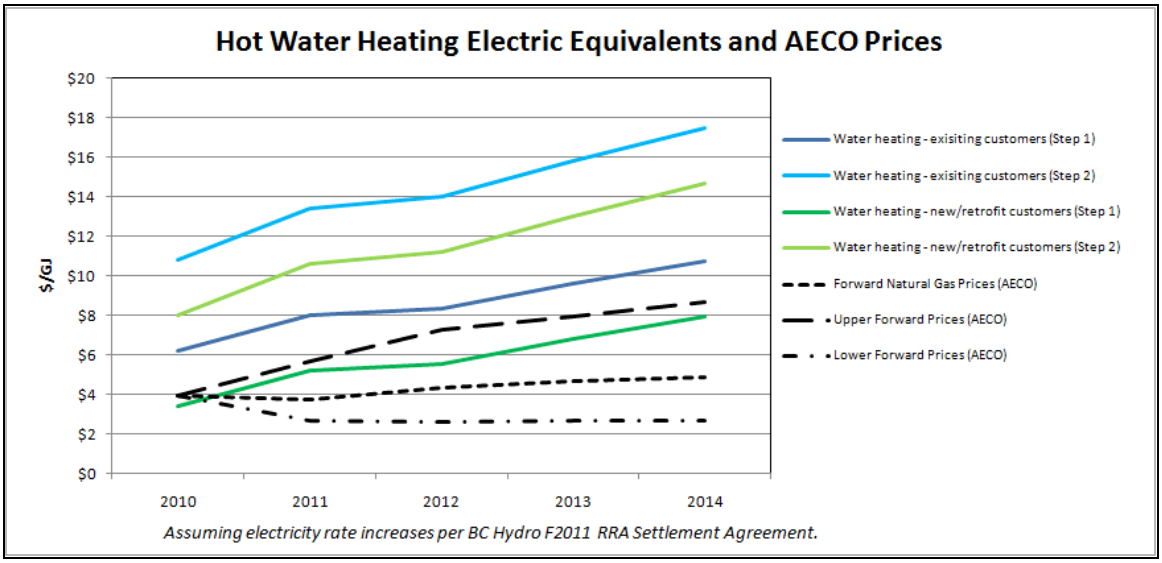
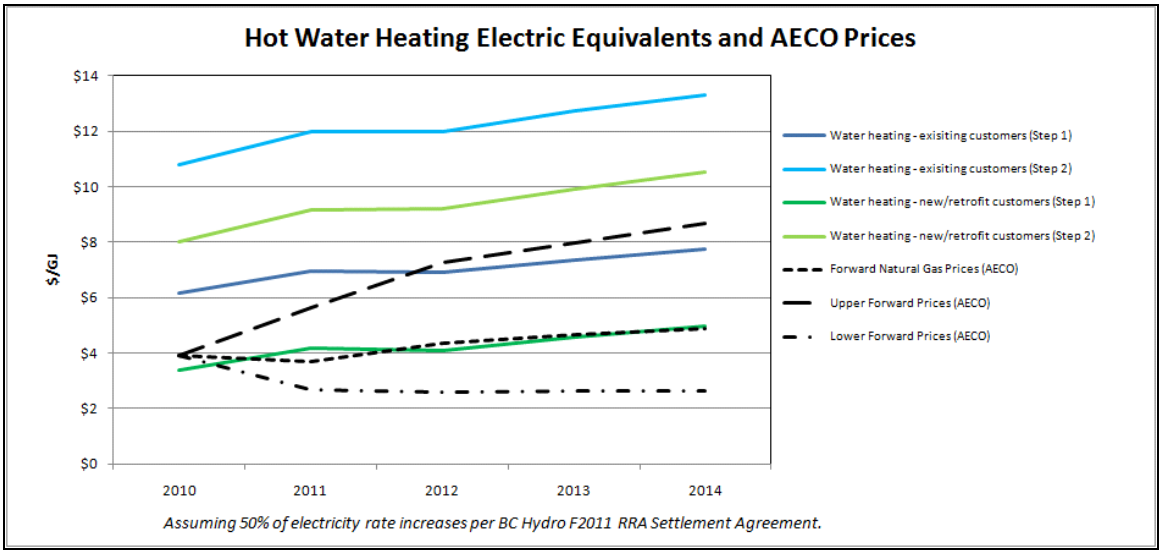



**Figure 3: TGI Electric Equivalent for Hot Water Heating with 50% of BC Hydro Projected Rate Increases**




It is important to note that AECO prices, while currently depressed relative to historical values, have averaged near $6/GJ for the past five years (2006 through 2010) and settled above $10/GJ at times in the recent past (July 2008).

**33. Reference: Exhibit B-1, Page 45**

> The 2008 Residential End Use Study ("REUS") provided support to the assertion that "customers change their consumption behaviour based on the real or perceived view that gas is uncompetitive with electricity or other sources of energy". In other words, more frequent rate changes or rate increases for natural gas than for electricity can create the perception that natural gas rates are uncompetitive on a variable cost basis with electricity while in fact the opposite may be true.

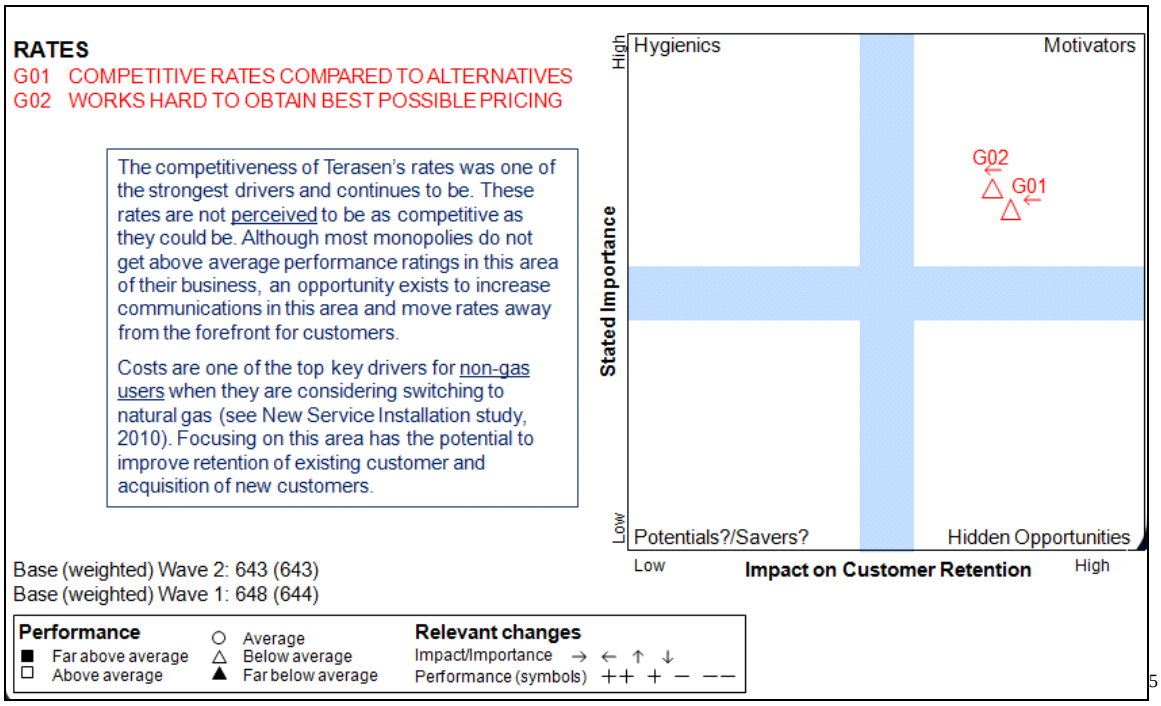
33.1 What evidence does FBU have that the customer is interpreting frequency of price change update with perceived uncompetitive energy supply source?

**Response:**

FBU does not have specific data that associates frequency of price changes with the perception of natural gas as an uncompetitive energy supply. Please see the response to CEC IR 1.5.1 regarding the difficulty of collecting this information.

However, as demonstrated in the 2008 REUS, price fluctuations and particularly price increases appear to influence consumer behaviour, especially in the long term. Additionally the 2008 REUS also shows supplemental use of electricity for space heating is on the rise even though many gas consumers for space heating would be competitive with electricity o n a variable cost basis. In a 2005 study, "A sizeable proportion (69%) of residential customers expressed a higher level of concern over future natural gas price fluctuations (7 or higher out of a possible 10). This stems from potentially having to pay more for a household "staple", which is a concern for people on fixed incomes, and those who don't want to pay more for natural gas."[4] This lends credibility to the belief that the price increases and volatility negatively affect consumer perceptions of competitiveness as demonstrated in a 2010 customer satisfaction survey. The finding is depicted in the table below:

[4] Residential Customer Price Volatility Preference Survey, Western Opinion Research, June 24, 2005, Page 6.



[5]

Despite significantly lower rates since mid 2009, customers remain concerned that natural gas is uncompetitive with other energy options. Based on statistical analysis, the research vendor concluded that this perception has a significant influence on customer retention (as depicted on the x-axis in the table above).

33.2 If this were true would it more exacerbated when the competitiveness of the price level is very close, as in the FBU past and less so when the competitiveness of the price improves as in the FBU future?

**Response:**

The 2008 Residential End Use Study was conducted when natural gas prices were substantially higher than at present, and the study concluded that natural gas price increases contributed to the decline in use rates, or the perception that natural gas was not price competitive. In addition to the information provided in the response to CEC IR 1.33.1, the Company is currently

[5] Terasen Gas Residential Customer Satisfaction Tracking, January 10, 2010, R1622, Page 29

conducting a 2010 Residential New Home Study that will evaluate dwelling characteristics and fuel usage in homes constructed between 2005 and 2010. The results may offer additional insight into changes in public perception of natural gas competitiveness since prices have been reduced.

However, with alternative energy technologies becoming more widespread, the possibility exists that consumers are not simply comparing natural gas with electricity, but also with additional alternatives that, in the long term, may offer consumers a perceived reduction in overall costs. As such, frequent natural gas fluctuations may continue to result in temporary and permanent fuel switching away from natural gas despite its improving price competitiveness relative to electricity.

**34. Reference: Exhibit B-1, Page 46**

- The difference in the variable component of natural gas and electricity rates
- The volatility of the variable component of rates
- The difference in upfront capital and maintenance costs of natural gas and electric space and hot water heating equipment
- Carbon tax on natural gas
- Public perception of natural gas relative to other energy sources

34.1 Is it not true that hedging can not affect these issues listed, except the volatility of the variable component rate?

**Response:**

An effective hedging program can affect some of the factors that impact competitiveness. Over the short term hedging horizon, hedging can affect the difference in the variable component of natural gas rates by impacting the underlying market prices embedded in gas costs. Hedging can also mitigate the volatility of market prices (by converting them from floating market index prices to fixed or fixed cap prices) and consequently natural gas rates. Lastly, hedging can also influence public perception regarding natural gas in terms of rates to some degree, given that frequent natural gas rate changes will be viewed negatively by some customers.

Hedging cannot directly influence the difference in capital costs or the carbon tax on natural gas. However, by mitigating the adverse effects of the other factors, the hedging program can help maintain competitiveness overall.

**35. Reference: Exhibit B-1, Page 52**

> this price level again in the future. Therefore, locking in a portion of gas costs through hedging at prices below these benchmark levels would certainly help Terasen in its ability to attract new or retrofit customers, grow its customer base and provide cost effective rates for all customers.

35.1 Locking in low prices may be useful, would FBU agree that hedging only provides a temporary ability to lock in prices and that FBU is not proposing any long term contract locking in of prices?

**Response:**

As discussed in the response to BCUC IR 1.4.1.2, hedging provides short term mitigation of price volatility and competitiveness for the hedging horizons defined within the FEI and FEVI Price Risk Management Plans. In the past, FEI has had a three year hedging horizon and FEVI has had a five year hedging horizon, due to its greater competitive challenge. Over the long run, beyond these hedging horizons, the energy marketplace, government policy and public perception towards energy and the role of natural gas in B.C. will determine the competitiveness of natural gas.

At this point in time, the Utilities are not proposing any longer term hedging beyond these hedging horizons. The proposed FEI 2011-2014 Price Risk Management Plan continues to include a three year hedging horizon.

**36. Reference: Exhibit B-1, Page 55**

> electric baseboard heating or an alternate source of energy. The 2008 REUS showed that many customers' furnaces were of a lower efficiency level. This indicates that a large proportion of lower efficiency furnaces will be replaced with higher efficiency units within the coming years, particularly for TGI. At that point, their electric equivalent commodity component becomes significantly lower, increasing the competitive challenge for Terasen.

36.1 How does natural gas furnace efficiency improvement create a negative competitive factor with electricity equivalent pricing once the higher efficiency furnace is in place, doesn't it improve commodity price competitiveness?

**Response:**

Yes, when comparing the cost effectiveness of installed furnaces, the more efficient furnace uses less gas to heat the same space and therefore will be more cost competitive. The discussion in the reference paragraph is referring to the decision that a customer must make at the time he is required to replace his current lower efficiency furnace. At that time he is comparing the installation of a new electric furnace to a new high efficiency furnace and would consider both the variable costs (i.e. natural gas versus electricity) and capital costs.

The commodity components of the electric equivalent benchmarks are different for existing customers versus new or retro-fit customers. This is because of the capital cost differences between natural gas and electric equipment that are considered when purchasing a new furnace. In other words, an energy consumer choosing between installing a natural gas furnace or electric baseboards in their home would consider the differences in the upfront equipment and installation costs as well as the variable costs over time, as discussed in Section 4.4.5.4 of the Review Report. Whereas, an existing customer, having already made the capital cost decision, is only concerned with the variable costs going forward. So even though the natural gas furnace efficiency would generally be higher for new or retro-fit customers as compared to existing customers, increasing the electric equivalent commodity component, the capital cost factor outweighs this benefit. As discussed in Section 4.4.5.2 of the Review Report and shown in Figure 18 on page 49, the estimated capital cost difference between natural gas and electricity for space heating is $10.31/GJ. This results in a lower electric equivalent commodity component overall and greater competitive challenge for natural gas in attracting these customers.

36.2 Isn't the building envelop heat retention really the competitive factor which is negative (it shrinks the space heat energy required, which increases the capital cost hurdle)?

**Response:**

The statement referenced in the question is made assuming that both the old, lower efficiency equipment and the new, higher efficiency equipment are appropriately sized to meet the buildings size and heat retention characteristics. As such, the capital cost differential between natural gas and electric heating equipment is the major competitive challenge for FBU. Changes made to the building envelop could improve the energy efficiency of the building such that a smaller furnace could adequately heat the building. The extent to which this situation could occur and to which the potential for installing a lower cost furnace could impact such an analysis can only be examined on a case by case basis.

**37. Reference: Exhibit B-1, Page 55**

> Natural gas is also disadvantaged in terms of competing with electricity with regard to attracting customers for hot water heating. While there is a capital cost differential related to hot water heating, the variable cost difference also challenges natural gas relative to electricity. This is because the relative efficiency of natural gas hot water heaters is typically only about 60% compared to about 90% efficiency for electric hot water heaters.

37.1 Why is the natural gas furnace less efficient?

**Response:**

The difference in efficiencies is due to the way cool air is warmed in a home by either type of heaters. In a natural gas furnace, hot combustion gases generated from the burning of natural gas pass through a heat exchanger where some of the heat energy from the hot gases is transferred to the cool air. The rest of the heat energy is lost with the combustion gases and vented to the atmosphere. Conversely, there are no combustion gases in an electric baseboard. Cool air is drawn into the electric unit through convection and warmed by the hot coils and fins heated through resistance in the coils.

37.2 Where does the additional heat go?

**Response:**

Some heat is lost with the combustion gases and vented to the atmosphere.

37.3 Can this additional heat be captured and recovered into space heating much of the year?

**Response:**

Additional heat can be captured and recovered through condensing furnaces that offer higher efficiencies than standard gas furnaces. Condensing furnaces use additional heat exchange surfaces to cool and condense the combustion gases, thus extracting more heat from the combustion gases prior to being vented to atmosphere which results in more heat for the home.

**38. Reference: Exhibit B-1, Page 61**

> Capturing natural gas prices, through hedging, at levels near current forward prices would help ensure that Terasen is able to improve its ability, at least on a variable cost basis, to maintain existing customers and attract new customers. However, without hedging, if market gas prices migrate towards the upper end of the forecast AECO price envelope, Terasen's competitive position is negatively impacted. If natural gas load migration occurs this would adversely affect both Terasen's and BC Hydro's rates as discussed in Section 4.4.1.

38.1 Isn't it true that hedging can not affect in the long term a high gas price market scenario?

**Response:**

Please refer to the responses to BCUC IRs 1.2.1, 1.4.1.2, 1.10.1.5, and 1.10.1.6.

38.2 Isn't it true that hedging can only deal with temporary price fluctuation volatility?

**Response:**

Please refer to the responses to BCUC IRs 1.4.1.4 and 1.4.2.3.

**39. Reference: Exhibit B-1, Page 61**

> The authors noted that in the short-term, price spikes can influence customers to temporarily turn primary natural gas heating systems off in favour of readily available alternative secondary heating options. This is evidenced by the widespread use of multiple heating fuels (e.g., wood) and heating appliances (e.g., portable electric heaters and fireplaces) in B.C. homes. The 2008 REUS found that 56% of the TGI customers surveyed used supplementary heating fuels for space heating.

39.1 Does this mean that existing customers already exercise some degree of response to price with temporary fuel switching but that they do not leave having natural gas as their dependable main source of heating?

**Response:**

The temporary use of secondary heating sources does not necessarily mean customers will exercise short term fuel switching while retaining natural gas as their primary fuel source in the long term. Rather, the 2008 Residential End Use study concluded that short term fuel switching is a temporary response to gas prices that, in the long term, can lead to permanent movement away from natural gas.

The 2008 REUS found on average that 3% of FEI customers changed their main space heating fuel in the last five years. Of the customers who switched from natural gas, 78% moved to electricity as their primary fuel source. Additionally, findings show that 57% of customers who changed their primary heating fuel in the past 5 years switched from natural gas as their space heating fuel, compared to 17% who switched from electricity. Proportionately, three times as many people switched to their current fuel from natural gas than from electricity.

Based on the 2008 REUS data, FBU believes that customers will exercise some degree of response to short term price increases that can contribute to customer migration to other primary energy sources in the long term.

39.2 Does FBU have a quantitative connection between temporary fuel switching and ultimate permanent fuel switching?

**Response**

FBU does not have any research establishing the quantitative connection between temporary fuel switching and ultimate permanent fuel switching. This analysis was not carried out in the 2008 Residential End Use Study but by looking at the fuel shares over time through end studies, it is not unreasonable to assume that there is a strong correlation between temporary and permanent fuel switching. A 2010 Residential New Home Study is currently underway to provide analysis and results for new housing stock built between 2006 and 2010. This study may provide additional insights into customer fuel choices and act as another data point for comparison purposes when the results become available.

Additionally, a 2006 study by the Colorado-based National Renewable Energy Laboratory (NREL) estimated the short-run price elasticity for natural gas in the Pacific Coast region of the U.S. (Washington and Oregon) to be -0.18 and the long-run price elasticity to be -0.63.[6] Although the results are not based on data from the FBU service territory, the calculated elasticities support the Company's assertion that there is a strong correlation between temporary and permanent response to price increases in the Pacific Coast region.

[6] Bernstein, M.A., and Griffin, J., *Regional Differences in the Price-Elasticity of Demand for Energy*, Subcontract Report for National Renewable Energy Laboratory, NREL/SR-620-39512, February 2006

**40. Reference: Exhibit B-1, Page 62**

> The 2008 REUS identifies trends in fuel switching away from natural gas. As participants in this research were required to be current TGI customers, estimates for fuel switching are likely underestimated. Former customers who switched to another primary fuel source, and did not retain any natural gas appliances are not reflected in the study. The 2008 REUS found on

40.1 This is an old study and the data contained therein are from customer decisions related to even earlier periods where natural gas was even more challenged by electricity prices, does FBU have any more recent data to show what the customer response is now that they are becoming familiar with significant electricity price increases?

**Response:**

FBU concedes that the data contained therein are from customer decisions related to even earlier periods where natural gas was even more challenged by electricity prices. However, results from the 2010 Terasen Gas Residential Customer Satisfaction Tracking study (please refer to the response to CEC IR 1.33.1) and other recent studies support FBU's assertion that customers perceive natural gas as uncompetitive with other energy options. In general, consumers still view electricity as a lower cost energy source.

The 2010 New Service Line Installation Study found that natural gas is not viewed strongly as a low cost energy source: 21% of non-gas users strongly believe that natural gas is more expensive than alternative fuels, including electricity, and when asked to think about whether or not they would switch to another fuel, approximately 50% of non-gas users strongly agree that their current heating fuel (typically electricity) is less costly than any alternative.

FBU has recently conducted a 2010 Residential New Home Study that evaluates the end-use breakdowns in homes built since 2005. The results of that study are not finalized yet; however preliminary analysis suggests that we may continue to see market share erosion, particularly in relation to water heating.

Although natural gas prices have softened since 2008 while electricity prices are steadily rising, these lower prices have not attracted an increase in the percentage of consumers that choose natural gas for primary and secondary space-heating. When the results of the 2010 Residential New Home Study are finalized, FBU will provide updates on customer responses to increased electricity prices and decisions on choice of fuel.

**41. Reference: Exhibit B-1, Page 63**

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

41.1 This seems like evidence for a high tolerance level, is there data available to differentiate the population to customers who may be more sensitive and would be more likely to switch?

**Response:**

Those customers more sensitive to changes in natural gas prices were classified in Appendix B of the Review Report. A wide sampling of participants was taken from various demographic groups such as different age groups, income levels, and education level completed to provide a broad range of preferences related to tolerance levels in changes to price for natural gas. The results of the study also conclude that the higher the average household natural gas bill, the higher the tolerable bill change is accepted, per pages 4 and 14 of the study in Appendix B of the Review Report. Also, the majority (about 70%) of respondents could only tolerate bill changes of $100, which is less than the overall average tolerance of $169. Intuitively, these customers might include people with smaller homes, less household income, or a combination of both. As such, these types of customers would be more sensitive to rate volatility and could potentially migrate away from natural gas.

More data and statistics can be found on page 29 of the second report titled, "Residential Customer Price Volatility Preference Survey" included in Appendix B of the Review Report.

**42. Reference: Exhibit B-1, Page 66**

> Customers' desire for stability is also reflected in enrolments for the Terasen Equal Payment Plan ("EPP"). The EPP provides customers with equal monthly bill payments for a twelve month period, based on their previous year's consumption volumes. Approximately 31% of customers are signed up for this billing option. While this acts to smooth customers' consumption via stable bill payments it does not affect underlying gas prices as per a price risk management program. In other words, under the EPP alone, consumers are artificially protected from market price volatility as they will ultimately have to pay the rate impacts of any market price fluctuations. Furthermore, under the EPP, the equal twelve month payment instalments are reviewed every three months and adjusted if necessary to reflect changes in weather, gas usage or gas rates. This is done to avoid significant billing adjustments at year end caused by

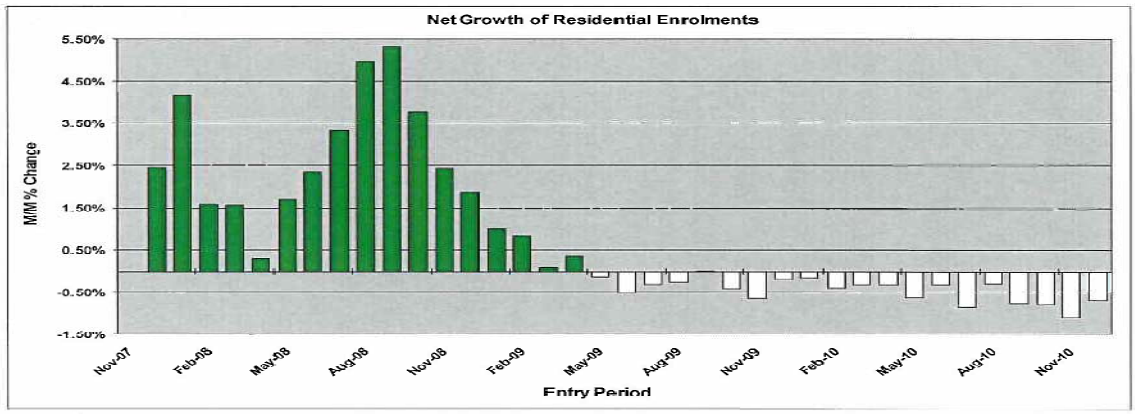
42.1 Please differentiate what hedging achieves versus what EPP achieves relative to reducing price volatility?

**Response:**

Please refer to the responses to BCOAPO IR 1.2.1 and BCUC IR 1.8.3.

**43. Reference: Exhibit B-1, Page 67**

**Figure 25: Customer Choice Program Net Residential Enrolments**




43.1 Do most customers wanting security from volatility already have the protection?

**Response:**

Please refer to the responses to BCUC IRs 1.4.1.5 and 1.4.1.7.

43.2 Is the decreased enrolment a reflection of customers learning about the cost of fixed price?

**Response:**

Please refer to the response to BCUC IR 1.7.1.4.

43.3 Is the issue of risk management still a necessity for those customers depending upon the ACP?

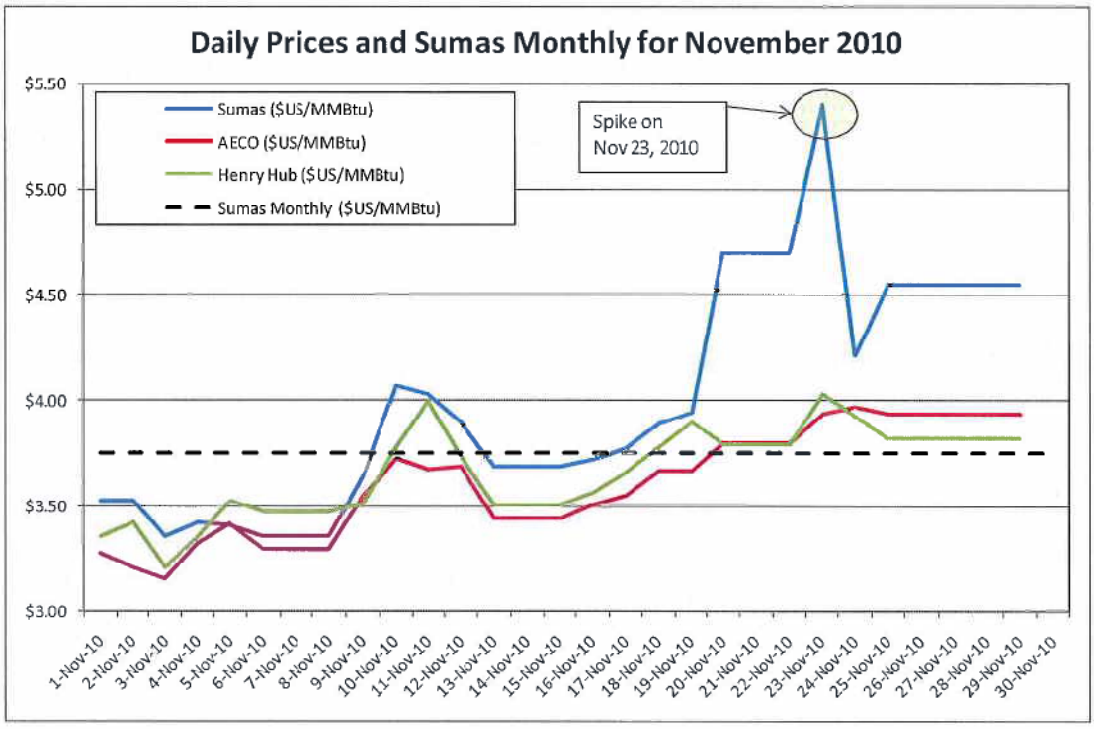
**Response:**

Yes, the issue of risk management is still a necessity for those customers depending upon the Annual Contracting Plan ("ACP"). As discussed in Section 4.2 of the Review Report, the ACP defines the physical resources, including commodity supply, storage and transportation,

required to meet forecasted core customer loads. The costs for these commodity and midstream resources are recovered from customers through rates. As this physical supply is based on index prices as determined in the natural gas market, effective price risk management and the hedging program are important in protecting customers from adverse market index price movements. Risk management from a security of supply perspective is also critical. The portfolio of secure, reliable and diverse resources ensures core customers' load requirements are cost effectively met each day, regardless of weather or market operating conditions.

**44. Reference: Exhibit B-1, Page 69**

**Figure 26: Daily and Monthly Sumas Prices for November 2010**

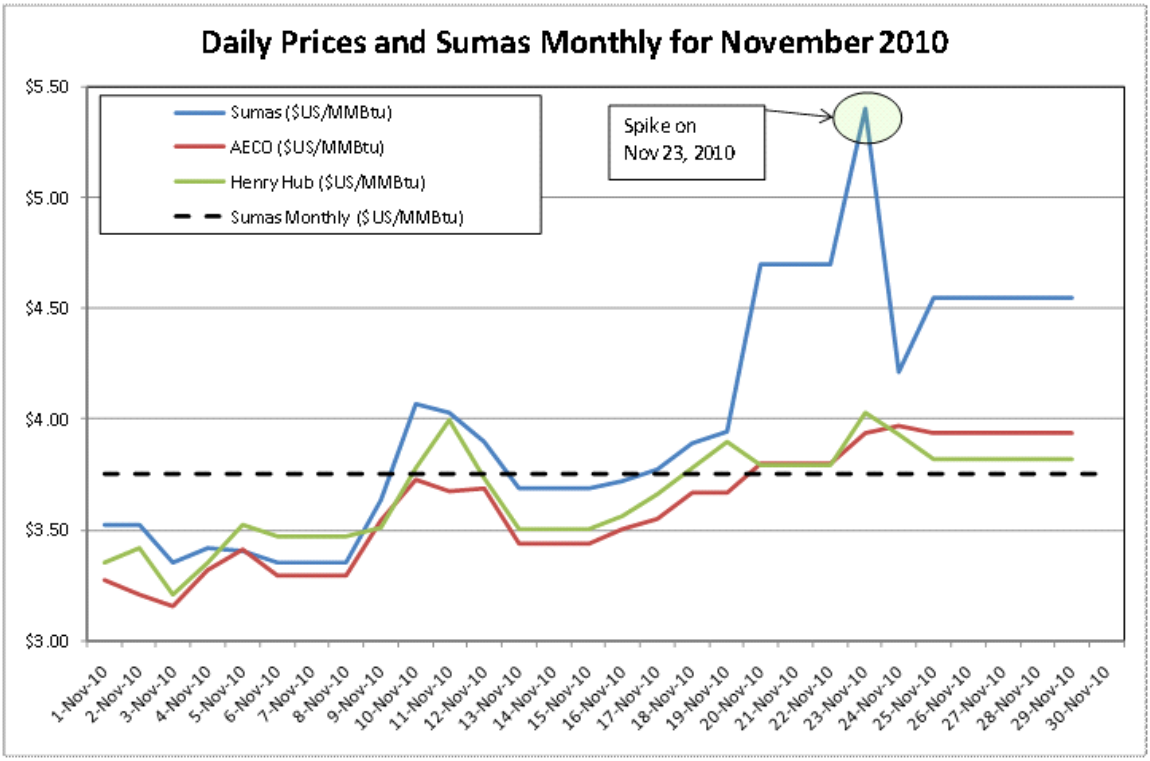



44.1 What caused this price spike and how much of this would the existing hedging program have mitigated and how much would the proposed hedging program have mitigated?

**Response:**

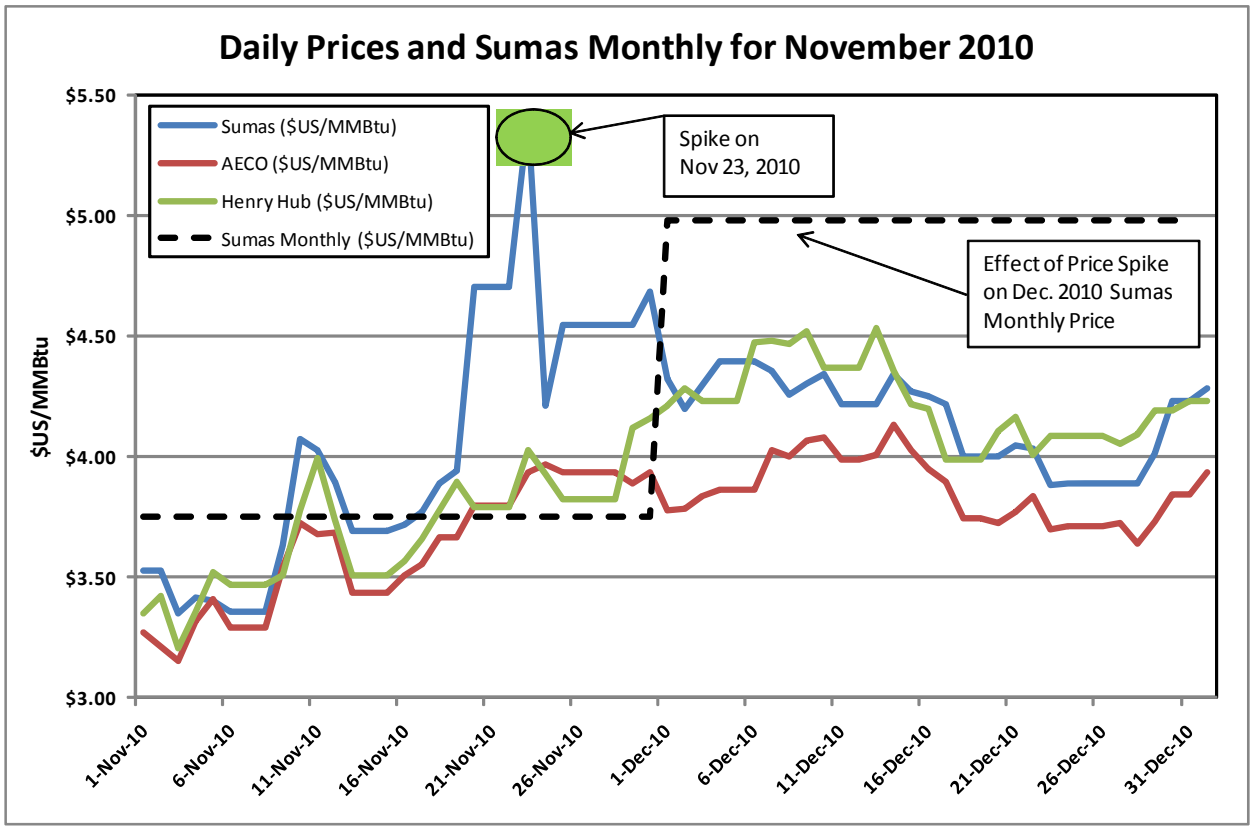
The price spike, shown in the figure below, was caused by much higher than normal demand in response to cold weather in the Pacific Northwest. This caused flowing volume at the Huntingdon/Sumas interconnect on the Spectra Pipeline to approach the maximum operating capacity thus causing a bidding up of the price at the Sumas pricing point.

**Figure 1: Sumas Price Disconnection for November 2010**




Note that the Sumas price spike occurred during the end of the month and this is when the monthly index price for the following month is calculated during the last five business days. The Sumas price spike resulted in the Sumas monthly index price to settle at $4.98 US/MMBtu. For instance, the Sumas price spike that occurred during the end of November 2010 caused the monthly Sumas price for December to be higher than it normally would have been since Sumas monthly prices are set during the last week of the preceding month. The figure below graphically illustrates the cause of the Sumas price spike on the monthly Sumas price for December 2010.

**Figure 2: Sumas Price Spike and December Monthly Price**




The price spike occurred from November 20 to November 30. For the November 2010 to March 2011 winter period, FEI currently has 24,000 MMBtu per day hedged with Sumas-AECO basis swaps at an average price of AECO Monthly CGPR 7A + $0.686 US/MMBtu. The calculation of the approximate savings of this basis swap hedge during the price spike is provided below.

**Table 1: Calculation of Realized Saving of Sumas-AECO Basis Swap for December 2010**

| | Sumas (IF)<br>$US/MMBtu | AECO (CGPR)<br>$US/MMBtu |
|---|---|---|
| Dec-10 | $4.98 | $3.7412 |
| | | |
| (1) | Gain from Difference in Sumas Monthly and AECO Monthly + Basis Premium | $0.55 |
| (2) | Number of Days in December | 31 |
| (3) | Daily Volume Hedged | 24,000 |
| (1)*(2)*(3) | Total Gain Realized | $ 411,283.20 |

The proposed hedging strategy will handle the above described scenario the same way since FEI is still proposing the use of basis swaps to help mitigate the risk of regional price disconnects. The strategy will still allow for the mitigation of price blow outs at Sumas while still allowing for participation for downward market price movements should AECO prices decline.

**45. Reference: Exhibit B-1, Page 72**

**Table 17: Value of TGI Sumas – AECO Basis Swaps**

| Term | Actual Basis ($US/MMBtu) | Terasen Gas Trades ($US/MMBtu) | Net Hedging Gain/(Cost) ($US/MMBtu) | Net Hedging Gain/(Cost) ($Cdn) |
|---|---|---|---|---|
| Winter 2000/01 | $2.69 | $0.27 | $2.42 | $11.2 million |
| Winter 2005/06 | ($0.10) | $0.31 | ($0.41) | ($2.0) million |
| Winter 2006/07 | $0.77 | $0.46 | $0.31 | $2.7 million |
| Winter 2007/08 | $1.13 | $0.77 | $0.36 | $2.6 million |
| Winter 2008/09 | $0.71 | $1.28 | ($0.57) | ($5.0) million |
| Winter 2009/10 | $0.70 | $0.80 | ($0.10) | ($0.7) million |
| **Weighted Average** | **$0.71** | **$0.76** | **($0.04)** | **$8.8 million** |

45.1 Would the hedging have been a loss without the California Crisis 2001?

**Response:**

There is no way of accurately knowing the effect of not having a catastrophic event happen, like the California crisis, would have had on the hedging gains or cost for this period. FEI believes that the mere occurrence of such an event just serves to underscore the importance of having Sumas basis swaps in the hedging portfolio and that a hindsight review of trying to predict what prices would have been in the absence of such an event provides no added value to whether Sumas basis swaps are warranted for use in an effective hedging program.

45.2 Does this demonstrate that cutting off big peaks in price fluctuations is useful but that at some point the hedging of smaller fluctuations becomes too costly for the benefit?

**Response:**

The Utilities agree that mitigating significant market price fluctuations is generally of greater value to customers than mitigating smaller market price movements, especially if this protection for the smaller market price movements comes at a significant cost. With natural gas market prices generally declining overall in the last few years, the Utilities have incurred hedging costs associated with mitigating market prices movements in general. However, the proposed

enhanced hedging program provides greater response to market conditions with an increased use of options when defensive tolerances are breached. With the reduction in programmatic hedging, continuation of basis hedging and addition of value and defensive hedging for low and high price scenarios, respectively, the enhanced hedging program is designed to significantly reduce the potential for out-of-market outcomes and hedging costs when protecting customers from market price volatility. This will effectively improve the benefits for customers relative to the potential costs going forward.

With respect to mitigating Sumas price exposure risk specifically, the Utilities believe that the continued use of basis swaps is prudent and appropriate. The transacted Sumas-AECO swaps have resulted in hedging gains since winter 2000/01 as shown in Table 17 on page 72 of the Review Report. If the hedging gains related to winter 2000/01 was removed from this table, a net hedging cost would have incurred instead (as discussed in the response to CEC IR 1.45.1). However, the Utilities believe that this cost is low in relation to the potential Sumas price volatility that has occurred in the past and will likely occur again in the future. With increased regional demand and constrained infrastructure as discussed in Section 4.6 of the Review Report, the Utilities believe that managing Sumas price risk through hedging continues to be in the best interests of customers.

45.3 Is there a role for TGI financing the volatility smoothing through deferral accounts?

**Response:**

As discussed in the response to CEC IR 1.45.2, the Utilities believe that the continued use of basis swaps to mitigate the Sumas price exposure risk is prudent and appropriate. In the absence of hedging the Sumas price exposure the variances between the actual incurred costs and the forecast costs embedded in recovery rates would be captured in the gas cost deferral accounts. Although the deferral accounting would smooth the impact of the market price fluctuations, any costs incurred due to volatility in the Sumas – AECO price differentials would ultimately have to be recovered from customers; the use of basis swaps reduces this price exposure.

**46. Reference: Exhibit B-1, Page 73**

> customers. It would be difficult for Terasen to incur no hedging costs each year while still managing competitiveness and volatility.

46.1 Does this mean that it would be difficult but not impossible?

**Response:**

As discussed in Section 4.7 of the Review Report and the response to BCUC IR 1.5.1.1, it would be extremely unlikely for the Utilities to obtain the lowest possible price and incur no hedging costs each year, given the volatility in the natural gas marketplace, while still managing competitiveness and volatility. As is common practice for Utilities, hedging is about providing insurance to protect gas customers from exposure to extreme price volatility and economic hardship, and it is NOT about market speculation or trading in and out to generate gains. Furthermore, to achieve this goal, considerable speculation regarding market price movements would likely be required. If undertaken by the Utilities, this endeavour could ultimately expose customers to greater risk and so would not be in the best interest of customers or meeting the objectives.

46.2 What are the other alternative FBU would look to in order to have lower hedging costs than would be the case if its recommended approach were used?

**Response:**

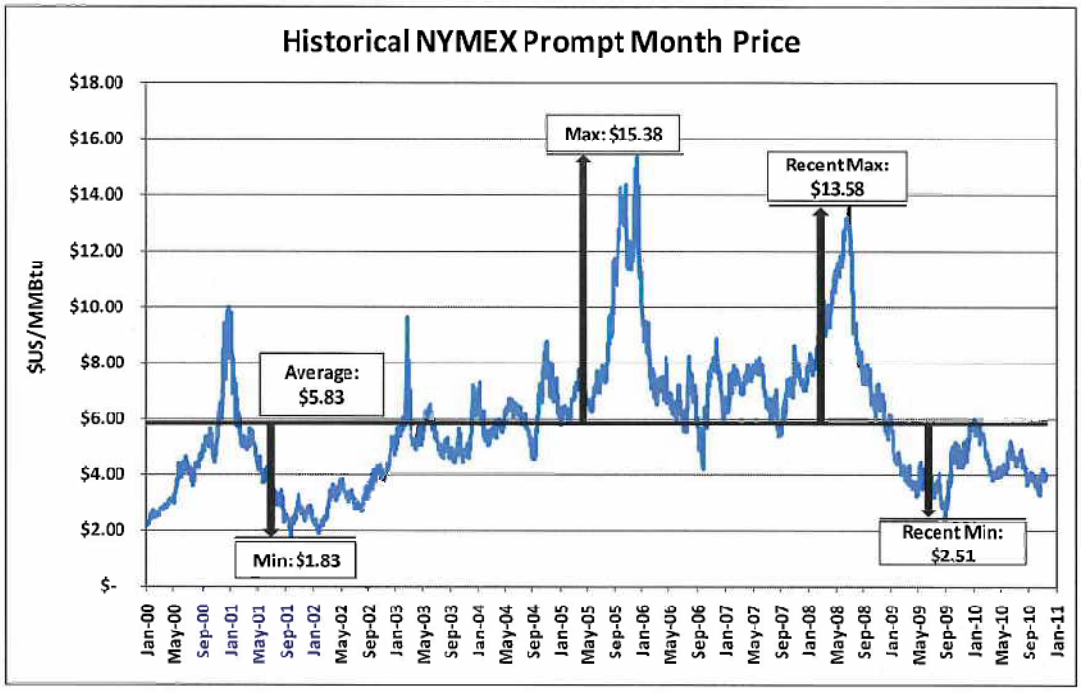
The Utilities believe that the proposed hedging strategy provides the appropriate balance of meeting the objectives of competiveness and rate stability while reducing the potential for significant hedging costs relative to the previous price risk management strategies. If the recommended strategy is not approved and FEI is directed to suspend its hedging activities, FEI could look to a greater amount of physical index based supply or greater use of storage capacity in the portfolio.

A greater amount of unhedged index priced gas supply in the portfolio exposes customers to greater market price fluctuations. Increasing storage capacity can provide greater security and reliability of supply but also increases associated storage and transportation fixed demand charges and variable costs which are flowed through to customers in rates.

Based on these considerations, the Utilities have recommended the enhanced hedging program, in combination with appropriate physical resources and effective management of deferral account balances, to meet the objectives at a reasonable cost for customers.

**47. Reference: Exhibit B-1, Page 74**

**Figure 30: Historical NYMEX Prompt Month Price**




47.1 Does this asymmetric price volatility mean there is a greater value in the option to cut off impacts from these spiky peaks, while simply smoothing the rest of the volatility fluctuations?

**Response:**

Asymmetric price movements, as described in Figure 30 on page 74 of the Review Report, gives greater value to options in managing market volatility. With market price movements limited by zero to the downside but unlimited to the upside, options are effective instruments if a balance of mitigating price volatility and reducing the potential for hedging costs is desired. For this reason, the consultant RiskCentrix and the Utilities have recommended an increased percentage of options as part of the defensive hedging strategy. The defensive hedging strategy is only utilized if market prices and volatility increase such that defensive tolerances are breached. If market prices remain stable and below these tolerances, defensive hedging and options are not required.

**48. Reference: Exhibit B-1, Page 75**

> In its report, RiskCentrix makes similar observations regarding the effectiveness of deferral accounts to manage rate stability. RiskCentrix notes that a short duration deferral account adds modest stability when used in conjunction with an effective hedge program but it is inferior as a stand-alone approach in the mitigation of price risk. Furthermore, the risk of deferral accounting is that deferrals could accumulate to unsustainable levels resulting in the need to ultimately pass through more costs. RiskCentrix's findings and view regarding this matter are included on page 24 of its report, provided in Appendix A.

48.1 Does this mean that FBU's proposed approach should be matched with appropriate deferral accounting approaches?

**Response:**

Yes, the proposed hedging strategy should be, and is, matched with appropriate deferral accounting approaches. As discussed in Section 5.1 of the Review Report, FEI uses a quarterly rate adjustment review mechanism to effectively manage the deferral account balances from becoming too large.

48.2 Would FBU agree that deferral accounts cannot climb to unsustainable levels if they have appropriate account clearing rules?

**Response:**

Yes. The Utilities are of the view that the current quarterly review and commodity rate setting process does provide for appropriate clearing of deferral accounts and reduces the potential for balances to climb to unsustainable levels.

48.3 What are FBU's proposed deferral account approaches in combination with the hedging?

**Response:**

The Utilities deferral account approach works in conjunction with the quarterly review and rate setting process. This approach is consistent with the Commission direction established pursuant to Commission Letter L-05-01 issued on February 5, 2001. Attached as Appendix I to Letter L-05-01 were the Commission's Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account Balance (the "Guidelines"). These Guidelines currently apply for the FEI Commodity Cost Reconciliation Account ("CCRA") and Midstream Cost Reconciliation Account ("MCRA"). The Utilities are not recommending any material changes to this approach at this time.

The Utilities note that any significant changes to the proposed hedging program could materially affect the variability between forecast and actual CCRA gas costs and subsequent deferral balances.

48.4 What are FBU's proposed deferral account clearing rules?

**Response:**

Please refer to the response to CEC IR 1.48.3.

**49. Reference: Exhibit B-1, Page 75 and 76**

> Currently, TGI uses a quarterly rate adjustment review mechanism to effectively manage the deferral account balances from becoming too large, as well as providing appropriate price signals as the commodity rate charged to customers better reflects the current market price of natural gas. The TGI Commodity Cost Reconciliation Account ("CCRA") became effective April 1, 2004 and since that time deferral account balances, on a net of tax basis, have generally been within a ± $50 million range (with any exceptions noted to date being surplus balances). Significantly high balances above this level can impact TGI's financial borrowing capacity and ultimately its risk profile. The quarterly review and opportunity to adjust deferral account balances provides timely management of these balances to an appropriate amount. This is in the best interests of customers, in terms of rate volatility mitigation, price transparency and reduced intergenerational inequities and allows for prudent financial management by the Company.

49.1 Does FBU have an analysis which shows that the deferral account process currently in use and the quarterly price is the optimal way to reduce price volatility?

**Response:**

FBU does not have an analysis which shows that the current deferral account process and rate setting mechanism is the optimal way to reduce price volatility. However, as discussed within the Review Report, gas cost deferral accounts and recovery mechanisms are commonly used by utilities to effectively manage the recovery of incurred gas costs from customers. While deferral accounts do provide some degree of rate volatility reduction, as compared to market gas price movements, the mechanisms should not be considered a replacement for natural gas hedging in effectively managing the market price volatility of natural gas. Gas cost deferral account mechanisms provide some rate stability by deferring the impact of commodity market volatility on gas costs. Hedging, on the other hand, mitigates the volatility in the incurred gas costs and therefore directly impacts the cost of gas.

In the RiskCentrix report, attached as Appendix A to the Review Report, similar observations are made regarding the effectiveness of deferral accounts to manage rate stability. RiskCentrix notes that a short duration deferral account adds modest stability when used in conjunction with an effective hedge program but it is inferior as a stand-alone approach in the mitigation of price risk.

The Companies believe its deferral account process and rate setting mechanism, used in conjunction with its proposed hedging program, is appropriate and prudent in meeting the objectives, including the reduction of price volatility.

Please also refer to the responses to CEC IRs 1.48.1 through 1.48.4.

49.2 What is the impact of the deferral accounts on the FBU credit and financial risk profile?

**Response:**

Large deficit deferral account balances would likely require FBU to increase its credit capacity in order to manage its monthly working capital requirements. Significant deferral account balances can impact FBU's increase FBU financial risk profile as the larger deferral accounts could lead to an increase in probability of loss on payment of amounts owed.

49.3 Would these risks be reasonable relative to the risks of loosing customer base?

**Response:**

FBU does not believe that higher deferral account balances offset the risks of reduction of the customer base, as the delay in flowing through gas cost increases does not fundamentally change the underlying cost of gas that may lead to a potential loss of customers. FBU believes the potential increased risks to financial risk profile related to significantly high deferral account balances would not be reasonable and it would not be prudent to allow deferral account balances to build to significant levels.

**50. Reference: Exhibit B-1, Page 77**

> In conclusion, the quarterly rate review mechanism provides effective management of deferral balances and appropriate price signals for customers. While the deferral balances do offer some degree of rate volatility mitigation, this is limited and does not provide the same degree of price risk mitigation as an effective hedging program.

50.1 What analysis and evidence supports this conclusion?

**Response:**

Please refer to the responses to BCOAPO IRs 1.2.1 and 1.2.2.

FEI believes the deferral account process and rate setting mechanisms, used in conjunction with the proposed hedging program, is appropriate and prudent in meeting the objectives, including the reduction of price volatility.

**51. Reference: Exhibit B-1, Page 84**

Objectives, and success metrics, must balance three competing tolerances:

- Customer bill increase tolerance;
- Out-of-market tolerance; and
- Option expenditure tolerance.

51.1 Please provide the metrics and supporting data showing the appropriate balancing of these tolerances?

**Response:**

The metrics used to evaluate each objective was provided by the consultant RiskCentrix as part of its analysis of the Utilities' hedging program.

Please refer to Section 7.1.3 of the Review Report for the details of the RiskCentrix analysis pertaining to the achievement of the objectives with an underlying objective of maintaining cost effectiveness of the portfolio.

51.2 Please provide the benchmark setting for the appropriate balance and how this will be maintained?

**Response:**

Specific benchmarks were not set for the determination of the appropriate balance of competing tolerances as described in Section 7.1.1 of the Review Report. However, in order to meet the objectives at a reasonable cost, it is recognized that the benefits of customer bill increase mitigation must exceed the cost to customers as determined by potential out-of-market hedging costs or option premium expenditures. Otherwise, the objectives would not be met in a cost effective manner. Based on analysis including market price simulations which incorporated a wide range of possible prices, the consultant RiskCentrix assessed various hedging strategies to achieve an optimal balance. The results of this analysis are provided in Section 1.7.3 of the Review Report. In particular, Table 18 on page 88 shows that hedging strategies to the right of the graph, with strategy G being the one recommended by FEI, provide significant volatility reduction in relation to potential hedging costs which include option premium expenditures. As such, the assessment of several hedging strategies under different market price scenarios,

rather than specific benchmarks, determined the appropriate and optimal balance of meeting the objectives.

Over time, the recommended hedging strategy can be assessed and, if necessary, adjusted to provide the optimal and appropriate balance in meeting the objectives.

**52. Reference: Exhibit B-1, Page 84**

a) Reduce Programmatic Accumulation - the proportion of hedges accumulated programmatically could be reduced from a target of about 50% of hedgeable volumes to 25%; this would constrain potential out-of-market settlements compared to current practice.

52.1 Please show how 25% was determined to be the most appropriate?

**Response:**

Please refer to analysis provided by RiskCentrix in Section 7.1.3 of the Review Report for the optimal selection of programmatic hedges and defensive hedging targets of the proposed enhanced hedging program.

52.2 Why would 35% or 15% not be more optimal?

**Response:**

Please refer to the response to CEC IR 1.52.1.

**53. Reference: Exhibit B-1, Page 84**

> b) Add Defensive Hedge Rules - Begin monitoring the potential for price migration of TGI's natural gas portfolio and set interim tolerances for defensive hedge responses. By deploying Value at Risk ("VaR") metrics, Terasen could delay hedge decisions until necessary, avoiding some risk of loss in down markets.

53.1 What specific data will be monitored and what will FBU be responding to what are the appropriate responses?

**Response:**

As part of the enhanced hedging strategy the Utilities will need to monitor a number of various market factors such as:

- Observed market price volatility;
- Term to maturity of hedging horizon;
- Forward settled prices; and
- Confidence interval of 95% or 2-sigma of price distributions.

By applying the recommended price propagation formulae to forward settled prices and comparing against predefined competitive benchmarks, as discussed in Section 4.4.5.4 of the Review Report, FEI will then be either not apply any hedges if these price triggers are not breached, or apply defensive hedging instruments if these predefined price triggers are beached.

**54. Reference: Exhibit B-1, Page 85**

> c) Add Value-Screening Criteria – Terasen currently deploys price targets for accelerated or incremental hedge accumulation. Those targets are determined based on current CCRA rates but could also include consideration of competitive benchmarks. Some form of risk/reward measure can help mitigate the potential for unfavorable settlements. The recommended value-screening criteria measures the degree of contango shape of the forward price curve and then provides an assessment of the risk/reward tradeoff attributable to incremental hedge commitments.

54.1 Please explain the proposed screening criteria and the methodology for making determinations for hedging commitments?

**Response:**

As discussed in Section 8.3 of the Review Report, FEI believes that a value hedging target below the $4.50/GJ level would help maintain historically low commodity rates and provide good value for customers. Furthermore, FEI is competitively challenged for new or retrofit hot water heating customers where the Step 1 rate is applicable. If 50% of the BC Hydro projected rate increases are approved, this benchmark target is near $4.00/GJ to $4.50/GJ from 2011 to 2014. Therefore, FEI believes that $4.25/GJ is an appropriate defensive hedging price target.

FEI would execute fixed price swaps equal to 1% of the hedgeable volume in each week for hedging terms where market prices are at or below this target. By layering in the value hedges in small increments, FEI captures more downside market price movement if prices continue to decline thus avoiding greater accumulation of out-of-market costs.

**55. Reference: Exhibit B-1, Page 85**

d) Call options could be deployed to a greater extent to draw a better balance between bill increase mitigation and out-of-market settlement potential. Because investment in option premiums is intended to acquire upside cost mitigation without the hedge loss potential associated with fixed price instruments, they are recommended in conjunction with defensive hedge rules. Also, since premiums increase with tenor, options should be deployed in the last year or two prior to settlement.

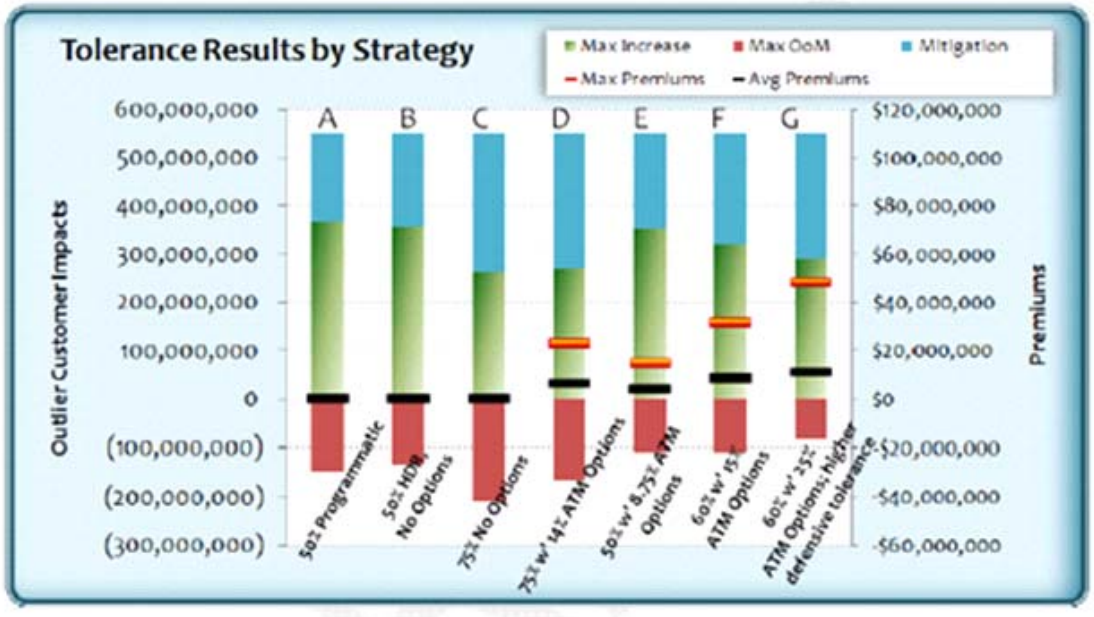
55.1 Please demonstrate and explain with a specific example how these call options would work and what they would cost?

**Response:**

Please refer to the responses to BCUC IRs 1.3.1.1 and 1.3.1.2 for a detailed explanation of how call options function.

For a detailed explanation of what call options *may* cost as part of the enhanced hedging strategy, the figure below from Section 7.1.3 of the Review Report, shows the relative cost of hedges for various price path propagations.

**Figure 1: Recommended Hedging Strategy**



Through consultation with Commission staff and RiskCentrix, strategy G specified in the figure above was selected as the optimal hedging strategy with respect to the use of options since it allows for the most mitigation of price volatility, reduced potential out-of-market outcomes, and reduced option premiums.

**56. Reference: Exhibit B-1, Page 85**

> targets were reached. Less programmatic hedging reduces the possibility of out-of-the-money outcomes while still providing some base amount of market price volatility reduction. Terasen believes that programmatic hedging of 25% is appropriate based in these considerations. The programmatic hedges would be implemented with fixed price swaps. The implementation schedule would extend out for three years and volumes would be accumulated in equal increments in each hedging window. This is consistent with TGI's past hedging horizon. The maximum volume that could be hedged, which includes any programmatic, defensive and value hedging, would be 60% of the hedgeable volumes for each of the summer and winter periods being hedged.

56.1 Is the accumulation in equal increments over 3 years in each hedging window the most optimal approach?

**Response:**

The Utilities believe that the accumulation of hedges in equal increments over three years in each hedging window is the appropriate and optimal approach for the programmatic hedging component of the proposed hedging strategy. As discussed in Section 8.1 of the Review Report, RiskCentrix recommends that the hedges are implemented in equal increments in each hedging window to provide price diversity and reduce the risk of hedging a large or more significant volume when prices are high, relative to recent historical averages. The three year hedging horizon provides a balance of mitigating short term market price volatility with reducing the potential out-of-market hedging costs and prudent management of counterparty credit risk.

56.2 Does FBU have data and analysis to demonstrate that this is an optimal design for its hedging or is it relying on the fact that this is similar to past practice?

**Response:**

The Utilities do not analysis to demonstrate that this is an optimal design for its programmatic hedging strategy. However, the Utilities are aware that this approach is consistent with that of other utilities that use hedging. Furthermore, the consultant RiskCentrix has recommended this approach based on its extensive experience with other utilities and in developing effective hedging programs. Also, based on past experience in dealing with market price volatility, the Utilities believe that this approach is optimal for the programmatic component of the hedging strategy.

**57. Reference: Exhibit B-1, Page 86**

> The tolerance targets for this defensive hedging could be related to the objectives and predefined with several tiers. For example, the first defensive price target could be reflective of the maximum tolerable bill increase related to customers' preferences. The remaining two defensive price targets could be based on the electric equivalent benchmarks as determined in Section 4. Predefined hedgeable volume percentages would be assigned to each of the targets and the maximum hedged volume of 60% of the hedgeable volumes, which includes programmatic, defensive and value hedges, would not be exceeded.
>
> The defensive hedging strategy uses more options than in past TGI hedging programs as these instruments provide effective upside cost mitigation while also reducing the potential out-of-the-money outcomes. The options would be limited to a maximum of 25% of the hedgeable volumes.

57.1 Why would external tolerances such as the electric equivalent benchmarks be relevant to hedging in a natural gas market?

**Response:**

The objectives of the Utilities hedging program are to reduce market price volatility and its impact on rates, maintain competitiveness with other sources of energy and reduce the risk of regional price disconnections. Therefore, external tolerances related to meeting these objectives, such as the electric equivalent benchmarks, are critically important in the hedging program. Electric equivalent benchmarks and customers' tolerances for bill changes are used to provide appropriate targets for hedging activity. Without these, the hedging program may not successfully meet the objectives.

57.2 Why wouldn't it be better to use risk and uncertainty profiles to determine targets instead?

**Response:**

As discussed in the response to CEC IR 1.57.1, external tolerances related to meeting the objectives, such as the electric equivalent benchmarks, are important targets for hedging activity. The Utilities have assumed that the reference to 'risk and uncertainty profiles' refers to the development of targets around market price movements. While this is an important consideration, the Utilities believe that targets related to customers' tolerance of these market price movements, rather than merely based on the market price movements themselves, is

more reflective of customers' interests. Similarly, with respect to competitiveness, benchmarks relating to specific price levels where customers could be incented to migrate to other energy sources, are more appropriate targets for meeting the objectives.