Last update on Feb. 6/07

Enbridge Gas
2007 Test Year Rate Case

EB-2006-0034

EXHIBIT LIST

K	Exhibits filed at the Hearing	Date Filed
	NO EXHIBITS WERE FILED	**January 22, 2007**
2.1	TABLE FORMING PART OF ENBRIDGE'S INTERROGATORY NO. 3 TO ENERGY PROBE, AND TABLE 1 AT EXHIBIT L, TAB 5, SCHEDULE 1 FROM THE PREFILED EVIDENCE OF TOM ADAMS	**January 29, 2007**
2.2	EXTRACT FROM NATURAL GAS FORUM DOCUMENT ENTITLED "NATURAL GAS REGULATION IN ONTARIO: A RENEWED POLICY FRAMEWORK", PROVIDED BY MR. BUONAGURO	
2.3	THREE-PAGE DOCUMENT FROM PREVIOUS UNION RATES CASE, ENTITLED "RISK MANAGEMENT IMPACT ON WACOG AND PGVA"	
2.4	ENERGY PROBE COMPENDIUM OF DOCUMENTS, ENTITLED "CROSS-EXAMINATION MATERIAL ON RISK MANAGEMENT, ENERGY PROBE RESEARCH FOUNDATION, JANUARY, 2007"	
2.5	ENBRIDGE CUSTOMER SURVEY ON RISK MANAGEMENT	
2.6	SPREADSHEET TITLED "ANALYSIS OF REVENUE TO COST RATIOS FOR RATE 1 AND ANALYSIS OF REVENUE TO COST RATIOS FOR RATE 6."	
3.1	VECC INTERROGATORY NO. 73 FROM EB-2005-0001	**January 30, 2007**
4.1	DOCUMENT ENTITLED "2007 TEST YEAR APPROXIMATE ELEMENTS OF CHANGES IN VOLUMES AND STORAGE DEFICIENCY AMOUNTS"	**February 1, 2007**
4.2	DOCUMENT ENTITLED: "COMPARISON OF NINE DIFFERENT DEGREE DAY FORECAST METHODOLOGIES"	
4.3	UNDERTAKING N3.2 FROM RP-2003-0063	
4.4	TABLE SHOWING ACTUAL AND FORECAST TORONTO DEGREE DAYS	

K	Exhibits filed at the Hearing	Date Filed
4.5	DOCUMENT ENTITLED "DEGREE DAY METHODOLOGIES - COMPARISON OF PERFORMANCE 1990-2005"	
4.6	ENERGY PROBE COMPENDIUM OF DOCUMENTS	
5.1	BREAKDOWN FOR ELECTRONIC PROGRAM DEFERRAL ACCOUNTS	**February 2, 2007**
5.2	DOCUMENT ENTITLED "ABC SERVICE FOR LARGE-VOLUME CUSTOMERS"	
5.3	COPY OF PAGE 43 OF EB-2006-0021 GENERIC DSM DECISION WITH REASONS	
6.1	COPY OF BUSINESS WEEK ARTICLE DATED JANUARY 29, 2007	**February 5, 2007**
6.2	PRICING SUPPLEMENT TO PROSPECTUS	
6.3	POLLUTION PROBE CROSS-EXAMINATION REFERENCE BOOK	
6.4	BUNDLE OF MATERIALS PROVIDED BY MR. POCH	
6.5	PAGES 32 AND 33 FROM EB-2006-0021	
6.6	PHASE I GENERIC DSM DECISION DATED AUGUST 26, 2006, IN EB-2006-0021	
7.1	DECISION AND ORDER OF THE BOARD IN RP-2002-0158	**February 6, 2007**
7.2	LETTER FROM MR. THOMPSON FROM MR. CASS DATED FEBRUARY 2, 2007	
7.3	EB-2005-0001 DECISION	
7.4	UPDATED CALCULATIONS SHOWING END-OF-DECEMBER RESULTS	
7.5	EXCERPT FROM BOARD’S DECISION IN EBRO 479	

J	Undertakings	Hearing Date	Response Filed
	NO UNDERTAKINGS WERE FILED	**January 22, 2007**	
		January 29, 2007	
2.1	ADVISE WHAT STEPS, IF ANY, HAVE BEEN TAKEN BY EGD TO EDUCATE CUSTOMERS IN RATES 100 OR HIGHER ABOUT THE COMPANY'S RISK MANAGEMENT PROGRAM AND THE NECESSITY, IF ANY, FOR THOSE CUSTOMERS TO UNDERTAKE THEIR OWN RISK MANAGEMENT		February 1, 2007
2.2	ADVISE WHETHER EGDI OBTAINS FINANCIAL INSTRUMENTS OR MECHANISMS FOR RISK MANAGEMENT PROGRAM FROM ANY AFFILIATES OR RELATED COMPANIES		February 1, 2007
		January 30, 2007	
3.1	PROVIDE DATA IN EXHIBIT K2.6 ON A STRICT CALENDAR-YEAR BASIS		
3.2	FILE ANALYSIS OF IMPACT OF MOVING RATE 1 TO REVENUE-T		
3.3	TO PROVIDE A BREAKOUT OF $16.1 MILLION AS BETWEEN UPDATED WEATHER METHODOLOGY, DECLINING AVERAGE USE, AND LOSS OF CONTRACT VOLUMES O-COST RATIO OF 1.0		
3.4	TO DETERMINE IF ANY PORTION OF ACCOUNT EXECUTIVES' COMPENSATION IS TIED TO THE ACCURACY OF THEIR FORECAST CONTRACT VOLUMES; IF ANY PORTION OF ACCOUNT EXECUTIVES' COMPENSATION IS TIED TO BEATING THEIR 2007 FORECAST OR ANY FORECAST FOR ANY YEAR		
3.5	PRODUCE FORECAST PRICE FOR 2007		
3.6	UPDATE TABLE 1 AT EXHIBIT I, TAB 2, SCHEDULE 27, PAGE 2		
3.7	TO ADVISE THE IMPACT OF A ONE PERCENT CHANGE IN THE PRICE OF GENERAL SERVICE VOLUMES		
3.8	TO PROVIDE A PRICE PER M^3 THAT CORRESPONDS TO THE 8.5 PERCENT UNDER THE 2007		
3.9	ADD THREE COLUMNS TO TABLE 4 ACTUAL THROUGHPUT VOLUMES; WEATHER NORMALIZED THROUGHPUT VOLUMES; BOARD-APPROVED THROUGHPUT VOLUMES		
3.10	TO PROVIDE ADJUSTED R-SQUARE VALUES FOR MODELS DESCRIBED IN TABLE 6 OF EXHIBIT C2, TAB 4, SCHEDULE 1		

J	UNDERTAKINGS	HEARING DATE	RESPONSE FILED
		February 1, 2007	
4.1	CONFIRM THAT WHEN APPLIED TO THE 2007 REVENUE REQUIREMENT, THE DIFFERENCE BETWEEN DE BEVER WEATHER METHODOLOGY AND 20-YEAR TREND METHODOLOGY IS $21.2 MILLION		
4.2	PORTION, IN DOLLARS, OF THE $21.2 MILLION IMPACT BETWEEN EXISTING AND PROPOSED METHODOLOGY THAT IS RATE 1 AND PROPORTION THAT IS RATE 6		
4.3	PRODUCE THE TREND LINE ON ACTUAL DATA FROM 1965 TO 2007 FOR ALL THREE REGIONS		
4.4	PROVIDE A VERSION OF K4.5, EXCLUDING THE DE BEVER, DE BEVER WITH TREND AND ENERGY PROBE METHODS, STARTING FROM THE YEAR 1976		
4.5	PROVIDE 20-YEAR DATA SET THAT TRACKS VARIATIONS FROM ACTUAL TO BOARD-APPROVED EACH YEAR FOR DEGREE DAYS AND FOR ROE		
4.6	REQUEST TO PROVIDE A TREND FORECAST FOR THE PERIOD 2007 TO 2012 AS A SIX-YEAR PERIOD USING THE PREVIOUS 30 SIX-YEAR PERIODS AS THE DATA SET		
4.7	UPDATE COLUMN 6 USING UPDATES TO COLUMN 7, WITH RESPECT TO REAL RESIDENTIAL NATURAL GAS PRICES FOR 2007 AND 2006, ON TABLE 2, UPDATES, TRY AND UPDATE A PROXY NUMBER FOR TABLE 3, GAS PRICES, WHICH CURRENTLY IS AT 48.6 OR NEGATIVE 48.6, WHICH APPEARS AT EXHIBIT C1, TAB 3, SCHEDULE 1, PAGE 8 OF 18		
4.8	PROVIDE EXPLANATION FOR THE DIFFERENCE IN THE REAL COMMERCIAL NATURAL GAS PRICE INCREASE IN 2007 AND 2008 AS COMPARED TO THE REAL RESIDENTIAL PRICE INCREASE		
4.9	TO PROVIDE THE PROBABILITY FIGURES ASSOCIATED WITH THE THREE VARIABLES THAT HAVE T STATISTICS ON PAGES 13 AND 14 OF EXHIBIT K4.6		
4.10	PROVIDE NORMALIZED 2006 NUMBERS, VOLUMES, SIMILAR TO TABLE 1 ON PAGE 25 OF 65 FOR AS MANY MONTHS OF ACTUALS AS AVAILABLE FOR 2006		
		February 2, 2007	
5.1	PROVIDE INFORMATION TO SHOW 1.8 PERCENT DECLINE IN AVERAGE USE BETWEEN 2001 AND 2005		
5.2	A SIMILAR THING FOR THE GAS PRICE IMPACTS SHOWN IN TABLES 4, 5 AND 6, EITHER INDIVIDUALLY OR IN AGGREGATE, OF ADJUSTING THE REAL COMMERCIAL PRICE TO REFLECT ACTUAL 2006 AND THE UPDATED FORECAST FOR 2007/2008		

J	UNDERTAKINGS	HEARING DATE	RESPONSE FILED
5.3	PROVIDE THE IMPACT ON THE DEFICIENCY OF USING A DEGREE DAY METHODOLOGY THAT CONSISTS OF A 50/50 WEIGHTING BETWEEN THE 20-YEAR TREND AND THE EXISTING APPROVED DE BEVER METHODOLOGY		
		February 5, 2007	
6.1	REDO TABLE 4 OF COMPANY'S EVIDENCE AT E2, TAB 1, SCHEDULE 1, WITH NORMALIZED RETURN ON EQUITY FOR YEARS 1993 TO 2005		February 6, 2007
6.2	TO PROVIDE THE BUDGET FOR THE 2006 BUSINESS DEVELOPMENT AND STRATEGY, AS ADJUSTED OR INCORPORATING THE CAPITALIZED AMOUNT REFERRED TWO FOR (1) THE PREFILED ESTIMATE AND (2) FOR THE ACTUAL		
6.3	PROVIDE REASONS FOR THE DECREASE IN THE ENERGY OPPORTUNITIES BUDGET FROM THE 2005 ACTUAL FIGURE TO THE 2006 BRIDGE YEAR ESTIMATE OF 1.177 MILLION, AS FOUND ON TABLE 1 ON PAGE 2 OF 10 IN THE POLLUTION PROBE DOCUMENT BOOK, TAB 3		
		February 6, 2007	
7.1	TO PROVIDE ADDITIONAL YEAR 2006 TO UNDERTAKING J6.1		
7.2	TO REVIEW EVIDENCE OF RP-2002-0158 AND CONFIRM WHETHER THERE WERE CHANGES IN BUSINESS RISK SUFFICIENT TO JUSTIFY AN INCREASE IN EQUITY RATIOS		
7.3	RECALCULATE THE INTEREST COVERAGE RATIOS IN COLUMN 9 IN ITEMS IN EXHIBIT E2, TAB 1, SCHEDULE 1, APPENDIX 3, ASSUMING THAT AMOUNTS PAID FOR CORPORATE COST ALLOCATION IN 2002-2006 INCLUSIVE ARE TO BE ADDED TO THE AMOUNTS IN COLUMN 8, ALONG WITH THE AMOUNTS PAID TO CWLP IN EXCESS OF BOARD-ALLOWED AMOUNTS FOR CUSTOMER SUPPORT		
7.4	2006 ACTUALS FOR LINE 1		
7.5	TO PROVIDE CLARIFICATION FOR COLUMN 7		
7.6	EXPLAIN THE DIFFERENCE IN VOLUMES ANTICIPATED FROM WATER HEATERS ON LINES 7, 10 AND 11		
7.7	TO VERIFY TRC AMOUNT OF $10.2 MILLION FOR FURNACE AND WATER HEATER LINES		
7.8	TO PROVIDE TRC FOR FIREPLACES UNDER ENERGYLINK PROGRAM		

K2.1

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Exhibit I
Tab 31
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d)

Impact of Risk Management on PGVA Reference Price
2002 -2006

Date	PGVA Reference Price $\$/10^3\ m^3$	Quarterly Price Change $\$/10^3\ m^3$	PGVA Reference Price without Risk Management $\$/10^3\ m^3$	Quarterly Price Change $\$/10^3\ m^3$	Variance $\$/10^3\ m^3$	% Reduction in Quarterly Price Change
1-Jan-02	220.462		218.221			
1-Apr-02	193.523	26.94	188.783	29.44	(2.50)	8.5
1-Jul-02	252.875	59.35	254.208	65.43	(6.07)	9.3
1-Oct-02	237.963	14.91	237.963	16.25	(1.33)	8.2
1-Jan-03	259.519	21.56	259.115	21.15	0.40	(1.9)
1-Apr-03	312.877	53.36	313.439	54.32	(0.97)	1.8
1-Jul-03	n/a *	n/a	n/a	n/a	-	-
1-Oct-03	280.181	32.70	280.075	33.36	-	-
1-Jan-04	263.197	16.98	262.337	17.74	(0.75)	4.2
1-Apr-04	292.891	29.69	293.175	30.84	(1.14)	3.7
1-Jul-04	332.911	40.02	334.344	41.17	(1.15)	2.8
1-Oct-04	332.236	0.67	332.236	2.11	(1.43)	68.0
1-Jan-05	356.327	24.09	358.784	26.55	(2.46)	9.3
1-Apr-05	319.285	37.04	318.199	40.58	(3.54)	8.7
1-Jul-05	355.705	36.42	355.784	37.58	(1.17)	3.1
1-Oct-05	396.567	40.86	395.464	39.68	1.18	(3.0)
1-Jan-06	484.195	87.63	484.973	89.51	(1.88)	2.1
1-Apr-06	399.582	84.61	396.467	88.51	(3.89)	4.4

*** No gas supply commodity change.**

e) If c) is agreed to, does Energy Probe agree that the percentage reduction in volatility on this basis has been much greater than plus or minus 1%?

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K2.1
DATE January 29, 2007.
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Impact of Risk Management on the Price Consumers Pay:

Recent Experience of Enbridge Distribution Inc.

13. Table 1 below has been inserted to demonstrate to the Board that despite the very impressive results the Applicant has been able to portray in its Prefiled Evidence, wherein it compared the Standard Deviations of its Unhedged and Hedged Portfolios[2], the results for residential customers are: in a word, negligible; in a percentage, not more than 1% either positive or negative since the April 1, 2002 QRAM.

Table 1

Risk Management Impact on PGVA Reference Price

Date	PGVA Reference Price Without RM $\$/10^3\ m^3$	PGVA Reference Price WITH RM $\$/10^3\ m^3$	Price Impact of Risk Management on PGVA Reference Price	Resulting Price Difference $\$/10^3\ m^3$	Resulting Price Impact: Expressed As a %
1-Jan-02	218.221	220.462	**Higher Price**	2.241	1.03%
1-Apr-02	188.783	193.532	**Higher Price**	4.749	2.52%
1-Jul-02	254.208	252.875	Lower Price	-1.333	-0.52%
1-Oct-02	237.963	237.963	**same**	none	none
1-Jan-03	259.115	259.519	**Higher Price**	0.404	0.16%
1-Apr-03	313.439	312.877	Lower Price	-0.562	-0.18%
1-Jul-03	313.439	312.877	Lower Price	-0.562	-0.18%
1-Oct-03	280.075	280.181	**Higher Price**	0.106	0.04%
1-Jan-04	262.337	263.197	**Higher Price**	0.86	0.33%
1-Apr-04	293.175	292.891	Lower Price	-0.284	-0.10%
1-Jul-04	334.344	332.911	Lower Price	-1.433	-0.43%
1-Oct-04	332.236	332.236	**same**	none	none
1-Jan-05	358.784	356.327	Lower Price	-2.457	-0.69%
1-Apr-05	318.199	319.285	**Higher Price**	1.086	0.34%
1-Jul-05	355.784	355.705	Lower Price	-0.079	-0.02%
1-Oct-05	395.464	396.567	**Higher Price**	1.103	0.28%
1-Jan-06	484.973	484.195	Lower Price	-0.778	-0.16%
1-Apr-06	396.467	399.582	**Higher Price**	3.115	0.79%
1-Jul-06	377.896	381.692	**Higher Price**	3.796	1.00%
1-Oct-06	377.896	381.692	**Higher Price**	3.796	1.00%

[2] Exhibit D1/Tab 4/Sched. 3, p. 6, Table 1

K2.2

Some of these stakeholders expressed the belief that unbundling is an integral element of facilitating competition, because, with unbundling, the market could provide these services to customers. This situation would increase customer choice by enabling customers to purchase the service or services that best suit their needs. Also, unbundling would ensure that the appropriate costs are included in the supply and delivery services and, as a result, customers could accurately compare costs between the different options in the marketplace.

The Board's Conclusions

Cost Allocation

The Board believes that the regulated gas supply option must be structured in a way that facilitates competition. The integrated nature of the supply and distribution services potentially makes the comparison between the regulated supply option and competitive supply options unbalanced. The current regulated gas supply costs include the cost of the commodity and limited overhead costs (such as risk management activities). Other overhead costs associated with the purchase, scheduling and management of gas supply and customer care costs are recovered through the distribution charges. Competitive supplier commodity charges reflect the overhead costs of sourcing, purchase and management of the gas function, including return. Therefore, questions are continually raised with the Board about whether distribution rates include supply costs and whether the rates for the regulated supply option hinder a viably competitive market where customers make decisions based on price.

In the Board's view, the pricing of the regulated gas supply option should minimize the potential for cross-subsidization between utility supply rates and distribution rates. The Board is not convinced one way or the other yet on the question of whether the current rates and/or rate structures contain cross-subsidies. It is of the view that the issue should be examined in a generic cost allocation hearing to determine the issue conclusively. The majority of stakeholders support this approach.

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K2.2
DATE January 29, 2007
09/99

The Board will hold a generic cost allocation hearing.

Further Unbundling

Some stakeholders advocated further unbundling to ensure transparency and to facilitate customer choice. These stakeholders clearly identified a set of discrete services for the regulated gas supply option and a separate set of discrete services related to the distribution function, as follows:

- delivery services: transportation and delivery of gas, including seasonal and peak load balancing of gas to end-use locations; emergency response and repair services
- supply services: purchase and sale of the gas commodity; price risk-management of gas commodity; customer care (which includes billing costs); annual (or three-point) load balancing

The Board believes it is necessary to make a clear distinction between the services provided as part of the regulated supply function and the services provided by the distribution function, and to consider unbundling these services to a greater extent. The Board is not convinced that further unbundling will jeopardize the utilities' ability to provide load balancing and other services to customers. Rather, the Board believes that further unbundling of utility services can bring the following significant benefits:

- improve market efficiency for all customers by increasing price transparency
- facilitate competition by moving the regulated gas supply option and competitive options towards a level playing field

The Board also believes that there is merit in moving towards policies that are consistent between utilities. At present, the load balancing policies of the two largest utilities differ – Enbridge has an annual obligation, while Union has a three-point obligation.[20] The Board will examine the issue of harmonizing the load balancing obligations between utilities in the generic cost allocation proceeding.

[20] In Union's latest rate case, RP-2003-0063, Union was asked by the Board to file a report regarding load balancing obligations and the regulated gas supply.

The Board will not go beyond unbundling to pursue functional separation at this time. While some stakeholders were of the view that the synergies between the supply and distribution functions underpin the utilities' ability to provide certain services, the Board does not agree that the integration of functions is absolutely necessary. The utilities could act as system operators and continue to provide their current services without having an integrated customer supply portfolio. However, the Board does not intend to pursue functional or structural separation of the supply and distribution functions. Further analysis is necessary to ensure that the benefits of such a change exceed the costs, and the Board does not consider this issue to be a priority at this time.

The Board will examine the issues related to further unbundling as part of the generic cost allocation hearing. This process will incorporate the work already under way on this topic.

The Pricing Mechanism

Stakeholders' Views

Most stakeholders expressed the view that there should be greater standardization of the QRAM process across utilities and that the QRAM should be more formulaic. Both Union and Enbridge expressed interest in further harmonizing the QRAM process, and Enbridge expressed the belief that consistency could be enhanced.

However, stakeholders expressed a variety of views about the pricing structure of the regulated gas supply option. Some stakeholders said that the existing quarterly revisions are appropriate, while others suggested that monthly revisions would better reflect the true cost of gas. The residential customer groups and the utilities supported quarterly price updates. The residential customer groups argued that quarterly price updates contribute to price stability, while the utilities said that quarterly updates help strike the correct balance between the desire for accurate price signals and the desire for reduced price volatility.

On the other hand, most of the marketers believed that the price should be revised monthly, to more accurately reflect gas price volatility and to reduce the PGVA and associated carrying costs. One stakeholder expressed the belief that a quarterly adjustment dampened the daily and monthly price fluctuations. This dampening reduced the difference between the marketers' fixed-price options and the regulated gas supply option, and possibly created a barrier to entry of new competitors into the market.

In terms of pricing, there was some support among stakeholders, including Union and Enbridge, for a regulated-utility, fixed-price, one-year contract offer to customers. However, the majority of stakeholders said that the utilities should not have the flexibility to provide fixed-term, fixed-price gas contracts. In particular, stakeholders argued that a fixed-term, fixed-price offer could:

- impede customer mobility;
- create a vested interest for utilities to maintain a minimum number of customers;
- create barriers to entry for new competitors; and
- compete directly with marketers.

Some support also existed for a spot price pass-through, to eliminate the utilities' risk-management activities and to accurately reflect the market price of gas.

The Board's Conclusions

In determining the appropriate pricing structure for regulated gas supply, the Board must consider the trade-off between a price signal that accurately reflects market prices and price stability. The current pricing process, whereby the price is set every three months on the basis of a 12-month price forecast, represents a balance between market-price signals and price stability. Therefore, from one perspective, the regulated gas supply price could be said to reflect a rolling one-year price.

The Board needs to consider whether the current balance between price signals and price stability is appropriate. In particular, it needs to address two key concerns:

- Is a 12-month price outlook appropriate as the basis for pricing the regulated gas supply option?
- Is the frequency of the price adjustment appropriate?

On the first issue, it may be appropriate for the price to reflect some other level of variation. In other words, instead of reflecting a rolling one-year price, the price could reflect a different time period. The question is, over what time period should the price outlook be based? The Board is not of the view that a spot price pass-through would be appropriate, because of the potential for volatility that would result. On the other hand, a reflection of seasonal price fluctuations could strike a reasonable balance among market price signals, administrative simplicity and customer acceptance. The Board would also need to consider the impact of such a change on the PGVA.

On the second issue, the Board recognizes the link between the utilities' actual procurement costs and the price set through the QRAM process. The utilities acquire supply in the marketplace primarily through monthly indexed contracts. The difference between the actual procurement costs and the price set through the QRAM process is collected in the PGVA. The amount in the PGVA is then recovered from customers. Customers, therefore, receive a supply that is priced monthly, although the price they see is smoothed over a specific time frame. At this time, the Board sees no compelling reason to depart from a quarterly price adjustment. However, if the time period of the price outlook were redefined, then the frequency of the price adjustment would need to be re-examined.

The Board believes that the QRAM price should be a transparent benchmark that reflects market prices, and, therefore, the methodology for calculating this price should be similar for all utilities. The market needs an accurate and consistent price signal, most stakeholders agree. Therefore, the Board believes, the method for determining the reference prices should be formulaic and consistent and, similarly, the methods for determining the PGVA and for disposing of PGVA balances should also be formulaic and consistent.

The Board will develop guidelines for the standardization of the quarterly rate adjustment mechanism, with the above objectives in mind. As part of this activity, the Board will consult in more detail on the underlying pricing that should be incorporated.

With respect to whether utilities should be able to offer fixed-term, fixed-price contracts, the Board concludes that it would not be appropriate at this time. The regulated gas supply option should be seen as a default supply – a no-written-contract, no-obligation, market-priced choice – where the mobility of the customer is essential. The Board believes that introducing a utility-provided fixed-term, fixed-price contract offer at this time would present two risks. First, the fixed-term aspect could reduce the utility's ability to ensure full customer mobility. Second, the fixed-price aspect would compete with the product offered by the retail marketers. It would move the regulated supply away from being a default supply, and result in more direct competition between the utility and competitive suppliers. A fixed-term, fixed-price contract offer would require substantial additional regulatory oversight related to the underlying contracting, the customer-utility interface and the allocation of risk. The Board does not believe that this is the appropriate direction to take, and most stakeholders shared this view.

The Board believes that a utility-provided fixed-term, fixed-price contract offer is inappropriate at this time.

Long-Term Supply and Transportation Contracts

Stakeholders' Views

Many of the stakeholders (including customers, upstream players and utilities) asserted that the regulated gas supply is implicitly used to underpin future infrastructure development in the natural gas market. Some emphasized the importance of the utilities' creditworthiness, noting that utilities are among the few parties able to enter into the long-term contracts needed for infrastructure development. Views on the appropriate

Some of these stakeholders expressed the belief that unbundling is an integral element of facilitating competition, because, with unbundling, the market could provide these services to customers. This situation would increase customer choice by enabling customers to purchase the service or services that best suit their needs. Also, unbundling would ensure that the appropriate costs are included in the supply and delivery services and, as a result, customers could accurately compare costs between the different options in the marketplace.

The Board's Conclusions

Cost Allocation

The Board believes that the regulated gas supply option must be structured in a way that facilitates competition. The integrated nature of the supply and distribution services potentially makes the comparison between the regulated supply option and competitive supply options unbalanced. The current regulated gas supply costs include the cost of the commodity and limited overhead costs (such as risk management activities). Other overhead costs associated with the purchase, scheduling and management of gas supply and customer care costs are recovered through the distribution charges. Competitive supplier commodity charges reflect the overhead costs of sourcing, purchase and management of the gas function, including return. Therefore, questions are continually raised with the Board about whether distribution rates include supply costs and whether the rates for the regulated supply option hinder a viably competitive market where customers make decisions based on price.

In the Board's view, the pricing of the regulated gas supply option should minimize the potential for cross-subsidization between utility supply rates and distribution rates. The Board is not convinced one way or the other yet on the question of whether the current rates and/or rate structures contain cross-subsidies. It is of the view that the issue should be examined in a generic cost allocation hearing to determine the issue conclusively. The majority of stakeholders support this approach.

The Board will hold a generic cost allocation hearing.

<u>Further Unbundling</u>

Some stakeholders advocated further unbundling to ensure transparency and to facilitate customer choice. These stakeholders clearly identified a set of discrete services for the regulated gas supply option and a separate set of discrete services related to the distribution function, as follows:

- delivery services: transportation and delivery of gas, including seasonal and peak load balancing of gas to end-use locations; emergency response and repair services
- supply services: purchase and sale of the gas commodity; price risk-management of gas commodity; customer care (which includes billing costs); annual (or three-point) load balancing

The Board believes it is necessary to make a clear distinction between the services provided as part of the regulated supply function and the services provided by the distribution function, and to consider unbundling these services to a greater extent. The Board is not convinced that further unbundling will jeopardize the utilities' ability to provide load balancing and other services to customers. Rather, the Board believes that further unbundling of utility services can bring the following significant benefits:

- improve market efficiency for all customers by increasing price transparency
- facilitate competition by moving the regulated gas supply option and competitive options towards a level playing field

The Board also believes that there is merit in moving towards policies that are consistent between utilities. At present, the load balancing policies of the two largest utilities differ – Enbridge has an annual obligation, while Union has a three-point obligation.[20] The Board will examine the issue of harmonizing the load balancing obligations between utilities in the generic cost allocation proceeding.

[20] In Union's latest rate case, RP-2003-0063, Union was asked by the Board to file a report regarding load balancing obligations and the regulated gas supply.

The Board will not go beyond unbundling to pursue functional separation at this time. While some stakeholders were of the view that the synergies between the supply and distribution functions underpin the utilities' ability to provide certain services, the Board does not agree that the integration of functions is absolutely necessary. The utilities could act as system operators and continue to provide their current services without having an integrated customer supply portfolio. However, the Board does not intend to pursue functional or structural separation of the supply and distribution functions. Further analysis is necessary to ensure that the benefits of such a change exceed the costs, and the Board does not consider this issue to be a priority at this time.

The Board will examine the issues related to further unbundling as part of the generic cost allocation hearing. This process will incorporate the work already under way on this topic.

The Pricing Mechanism

Stakeholders' Views

Most stakeholders expressed the view that there should be greater standardization of the QRAM process across utilities and that the QRAM should be more formulaic. Both Union and Enbridge expressed interest in further harmonizing the QRAM process, and Enbridge expressed the belief that consistency could be enhanced.

However, stakeholders expressed a variety of views about the pricing structure of the regulated gas supply option. Some stakeholders said that the existing quarterly revisions are appropriate, while others suggested that monthly revisions would better reflect the true cost of gas. The residential customer groups and the utilities supported quarterly price updates. The residential customer groups argued that quarterly price updates contribute to price stability, while the utilities said that quarterly updates help strike the correct balance between the desire for accurate price signals and the desire for reduced price volatility.

On the other hand, most of the marketers believed that the price should be revised monthly, to more accurately reflect gas price volatility and to reduce the PGVA and associated carrying costs. One stakeholder expressed the belief that a quarterly adjustment dampened the daily and monthly price fluctuations. This dampening reduced the difference between the marketers' fixed-price options and the regulated gas supply option, and possibly created a barrier to entry of new competitors into the market.

In terms of pricing, there was some support among stakeholders, including Union and Enbridge, for a regulated-utility, fixed-price, one-year contract offer to customers. However, the majority of stakeholders said that the utilities should not have the flexibility to provide fixed-term, fixed-price gas contracts. In particular, stakeholders argued that a fixed-term, fixed-price offer could:

- impede customer mobility;
- create a vested interest for utilities to maintain a minimum number of customers;
- create barriers to entry for new competitors; and
- compete directly with marketers.

Some support also existed for a spot price pass-through, to eliminate the utilities' risk-management activities and to accurately reflect the market price of gas.

The Board's Conclusions

In determining the appropriate pricing structure for regulated gas supply, the Board must consider the trade-off between a price signal that accurately reflects market prices and price stability. The current pricing process, whereby the price is set every three months on the basis of a 12-month price forecast, represents a balance between market-price signals and price stability. Therefore, from one perspective, the regulated gas supply price could be said to reflect a rolling one-year price.

The Board needs to consider whether the current balance between price signals and price stability is appropriate. In particular, it needs to address two key concerns:

- Is a 12-month price outlook appropriate as the basis for pricing the regulated gas supply option?
- Is the frequency of the price adjustment appropriate?

On the first issue, it may be appropriate for the price to reflect some other level of variation. In other words, instead of reflecting a rolling one-year price, the price could reflect a different time period. The question is, over what time period should the price outlook be based? The Board is not of the view that a spot price pass-through would be appropriate, because of the potential for volatility that would result. On the other hand, a reflection of seasonal price fluctuations could strike a reasonable balance among market price signals, administrative simplicity and customer acceptance. The Board would also need to consider the impact of such a change on the PGVA.

On the second issue, the Board recognizes the link between the utilities' actual procurement costs and the price set through the QRAM process. The utilities acquire supply in the marketplace primarily through monthly indexed contracts. The difference between the actual procurement costs and the price set through the QRAM process is collected in the PGVA. The amount in the PGVA is then recovered from customers. Customers, therefore, receive a supply that is priced monthly, although the price they see is smoothed over a specific time frame. At this time, the Board sees no compelling reason to depart from a quarterly price adjustment. However, if the time period of the price outlook were redefined, then the frequency of the price adjustment would need to be re-examined.

The Board believes that the QRAM price should be a transparent benchmark that reflects market prices, and, therefore, the methodology for calculating this price should be similar for all utilities. The market needs an accurate and consistent price signal, most stakeholders agree. Therefore, the Board believes, the method for determining the reference prices should be formulaic and consistent and, similarly, the methods for determining the PGVA and for disposing of PGVA balances should also be formulaic and consistent.

The Board will develop guidelines for the standardization of the quarterly rate adjustment mechanism, with the above objectives in mind. As part of this activity, the Board will consult in more detail on the underlying pricing that should be incorporated.

With respect to whether utilities should be able to offer fixed-term, fixed-price contracts, the Board concludes that it would not be appropriate at this time. The regulated gas supply option should be seen as a default supply – a no-written-contract, no-obligation, market-priced choice – where the mobility of the customer is essential. The Board believes that introducing a utility-provided fixed-term, fixed-price contract offer at this time would present two risks. First, the fixed-term aspect could reduce the utility's ability to ensure full customer mobility. Second, the fixed-price aspect would compete with the product offered by the retail marketers. It would move the regulated supply away from being a default supply, and result in more direct competition between the utility and competitive suppliers. A fixed-term, fixed-price contract offer would require substantial additional regulatory oversight related to the underlying contracting, the customer-utility interface and the allocation of risk. The Board does not believe that this is the appropriate direction to take, and most stakeholders shared this view.

The Board believes that a utility-provided fixed-term, fixed-price contract offer is inappropriate at this time.

Long-Term Supply and Transportation Contracts

Stakeholders' Views

Many of the stakeholders (including customers, upstream players and utilities) asserted that the regulated gas supply is implicitly used to underpin future infrastructure development in the natural gas market. Some emphasized the importance of the utilities' creditworthiness, noting that utilities are among the few parties able to enter into the long-term contracts needed for infrastructure development. Views on the appropriate

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Risk Management Impact on WACOG & PGVA

Union Gas

	Alberta Border Reference Price			PGVA Activity			Risk Management Impact on PGVA Clearing		
Effective Date	Alberta Border Approved WACOG (Cdn $ / GJ) (A)	Alberta Border Approved WACOG Excluding Forecast Risk Management (Cdn $ / GJ) (B)	Forecast RM vs No RM (A vs B)	Actual PGVA Deferral Activity ($millions) (C)	PGVA Deferral Activity if No Risk Management ($millions) (D)	Actual Versus No Risk Management (C vs D)	Rate Rider to Clear PGVA Activity (cents / m^3) (E)	Rate Rider to Clear PGVA Activity if no RM (cents / m^3) (F)	Actual Versus No Risk Management (E vs F)
Jan-03	$ 4.95	$ 4.95	0%	$ 50.5	$ 50.0	1%	2.0	1.9	5%
Mar-03	$ 5.82	$ 5.81	0%	$ 66.1	$ 110.4	-40%	2.6	4.3	-40%
May-03	$ 6.45	$ 6.43	0%	$ 3.2	$ 1.2	163%	0.1	0.0	0%
Jul-03	$ 6.67	$ 6.58	1%	$ 10.2	$ 14.7	-30%	-0.4	-0.6	-33%
Oct-03	$ 5.82	$ 5.50	5%	$ 8.6	$ 15.5	-44%	-0.3	-0.6	-50%
Jan-04	$ 5.48	$ 5.34	3%	$ 35.7	$ 28.6	25%	1.3	1.0	30%
Apr-04	$ 6.32	$ 6.19	2%	$ 6.7	$ 9.1	-27%	0.2	0.3	-33%
Jul-04	$ 7.26	$ 7.19	1%	$ 27.8	$ 27.5	1%	-1.0	-1.0	0%
Oct-04	$ 7.37	$ 7.20	2%	$ 8.2	$ 5.7	42%	-0.3	-0.2	50%
Jan-05	$ 7.81	$ 7.87	-1%	$ 31.8	$ 39.6	-20%	-1.1	-1.3	-15%
Apr-05	$ 7.18	$ 6.98	3%	$ 1.3	$ 0.0	100%	0.0	0.0	0%
Jul-05	$ 8.01	$ 7.83	2%	$ 5.1	$ 9.8	-48%	0.2	0.3	-33%
Oct-05	$ 9.08	$ 8.91	2%	$ 72.5	$ 86.9	-17%	2.5	3.0	-17%
Jan-06	$ 10.86	$ 10.86	0%	$ 45.3	$ 49.6	-9%	-1.6	-1.7	-6%
Total				$ 372.8	$ 448.5	-17%			
Average	$ 7.08	$ 6.98	1.5%				Abs Value Avg 1.0	Abs Value Avg 1.2	-16%
Standard Deviation	$ 1.5	$ 1.5	-1%	$ 23.4	$ 31.8	-26%	1.3	1.6	-21%

Conclusions:

(1) Risk Management Forecast has minimal impact on the setting of Union's WACOG.

(2) Over the long term, actual Risk Management costs(credits) has minimal impact on Union's Cost of Gas but does reduce the monthly volatility.

(3) Union's actual Risk Management has reduced the deferral activity and the subsequent disposition required to clear PGVA deferral accounts through the QRAM process.

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K2.3

DATE January 29, 2007

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Response to Energy Probe's Notice of Questions, May 25, 2006

Union Gas

Alberta Border Reference Price / Risk Management Impact on PGVA Clearing

Effective Date	Alberta Border Approved WACOG (Cdn cents / m^3)	Alberta Border Approved WACOG Excluding Forecast Risk Management (Cdn cents / m^3)	Forecast RM vs No RM	Rate Rider to Clear PGVA Activity (cents / m^3)	Rate Rider to Clear PGVA Activity if no RM (cents / m^3)	Difference Between RM and No RM (cents / m^3)	(E-F) as % of Average Cost of Gas
	(A)	(B)	(A vs B)	(E)	(F)	(E-F)	(G)
Jan-03	18.6	18.6	0%	2.0	1.9	0.1	0%
Mar-03	21.9	21.9	0%	2.6	4.3	-1.7	-7%
May-03	24.3	24.2	0%	0.1	0.0	0.1	0%
Jul-03	25.1	24.8	1%	-0.4	-0.6	-0.2	-1%
Oct-03	21.9	20.7	5%	-0.3	-0.6	-0.3	-1%
Jan-04	20.6	20.1	3%	1.3	1.0	0.3	1%
Apr-04	23.8	23.3	2%	0.2	0.3	-0.1	0%
Jul-04	27.3	27.1	1%	-1.0	-1.0	0.0	0%
Oct-04	27.8	27.1	2%	-0.3	-0.2	0.1	0%
Jan-05	29.4	29.6	-1%	-1.1	-1.3	-0.2	-1%
Apr-05	27.0	26.3	3%	0.0	0.0	0.0	0%
Jul-05	30.2	29.5	2%	0.2	0.3	-0.1	0%
Oct-05	34.2	33.5	2%	2.5	3.0	-0.5	-2%
Jan-06	40.9	40.9	0%	-1.6	-1.7	-0.1	0%
Total							
Average	**26.6**	**26.3**	**1.5%**	Abs Value Avg **1.0**	Abs Value Avg **1.2**		**-1%**
Standard Deviation	**5.6**	**5.7**	**-1%**	**1.3**	**1.6**		

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Risk Management Program - Impact 1998-2005

Union Gas

Volatility (Standard Deviation)	1998	1999	2000	2001	2002	2003	2004	2005	1998-2005 Total
Union's Monthly Actual Cost of Gas (Cdn$/GJ)	$ 0.31	$ 0.34	$ 1.16	$ 1.21	$ 0.66	$ 0.57	$ 0.68	$ 2.06	
% of avg annual price	8%	8%	24%	18%	15%	9%	10%	23%	
Market (NYMEX Monthly Settles) (US$/mmbtu)	$ 0.20	$ 0.44	$ 1.18	$ 2.26	$ 0.65	$ 1.26	$ 0.90	$ 2.99	
% of avg annual price	9%	19%	30%	53%	20%	23%	15%	35%	
Union's Volatility Reduction Versus Market	**-15%**	**-57%**	**-20%**	**-67%**	**-26%**	**-62%**	**-34%**	**-32%**	**-39%**

Mark to Market (millions Cdn $)	1998	1999	2000	2001	2002	2003	2004	2005	1998-2005 Total
Actual Mark to Market Credits(Costs)	$ (3.5)	$ 0.1	$ 41.6	$ (65.5)	$ (19.9)	$ 30.4	$ (1.9)	$ 9.9	**$ (8.7)**
% of Annual Commodity Costs	**0%**	**0%**	**-6%**	**8%**	**6%**	**-4%**	**0%**	**-1%**	**0%**

Union's Avg Annual Cost of Gas (Cdn $ / GJ)	1998	1999	2000	2001	2002	2003	2004	2005	1998-2005 Average
Actual With Risk Management Impact	$ 3.95	$ 4.11	$ 4.77	$ 6.85	$ 4.39	$ 6.40	$ 6.96	$ 8.78	$ 5.78
Assumes No Risk Management	$ 3.94	$ 4.11	$ 5.06	$ 6.33	$ 4.13	$ 6.69	$ 6.94	$ 8.87	$ 5.76
% of Commodity Costs	**0%**	**0%**	**-6%**	**8%**	**6%**	**-4%**	**0%**	**-1%**	**0%**

Exhibit K.24

EB-2006-0034

Cross-Examination Materials

On

Risk Management

Energy Probe Research Foundation

January, 2007

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K.24
DATE January 29, 2007
08/99

5. RISK MANAGEMENT

5.1 BACKGROUND

5.1.1 The role of and nature of the risk management program has been the subject of continuous revision and evolution. The very purpose of the program, as well as the rules governing its execution, has changed markedly over the last few years. As part of this process, Enbridge was required to procure expert advice and to present the resulting report to the Board. Enbridge retained RiskAdvisory, a recognized expert in the design and implementation of risk management activities at utilities. The resulting RiskAdvisory report was filed in the RP-2003-0203 proceeding and contained 16 recommendations. In that proceeding, Enbridge addressed seven of the RiskAdvisory recommendations and advanced three of its own proposals for changes in the program. In the current proceeding, Enbridge brought forward its plans for implementing the remaining nine recommendations.

5.1.2 Specifically, Enbridge is seeking Board approval for two aspects of the risk management program:

- an increase in the price volatility tolerance band from the current $35 level to $75 level, based on the findings of the Customer Threshold for Gas Supply Volatility Study; and
- the closing to rate base of approximately $930,000 related to the transition of the program from a spreadsheet format to a database format.

5.2 THE CUSTOMER THRESHOLD FOR GAS SUPPLY VOLATILITY STUDY

5.2.1 In RP-2003-0203, Enbridge indicated the need to survey its customers in order to better understand their sensitivity to price volatility and to use these findings to update the $35 price volatility tolerance level identified in the surveys undertaken in 1994 and 1995.

Enbridge commissioned Ipsos-Reid to conduct the survey and identified the following specific objectives for the research:

- Assess customers' level of knowledge, understanding and expectations about gas pricing and the Company's role in the process.
- Determine customers' expectations about gas prices and their sensitivity to price volatility.
- Understand customers' preferences for risk management strategies in general and under different market conditions.
- Determine customers' preferences for the frequency of bill adjustments.

5.2.2 According to Enbridge, the results of the survey indicated that customers are tolerant of fluctuations of less than $75 in the commodity portion of their annual bill. A significant majority of customers indicated a preference that price volatility risk be managed. Customers were also asked about their preference for risk management strategies. Enbridge reported that while under a variety of scenarios a vast majority of customers indicated a desire for some form of hedging activity, they were generally evenly divided in choosing among the alternatives.

5.2.3 Given the survey results, Enbridge requested Board approval for an increase in the price volatility tolerance band from the current $35 to $75. It further stated that there would be no change in the hedging methodology employed, which was previously approved in RP-2003-0203. The proposed change in the volatility tolerance band has the effect of materially reducing the amount of hedging activity authorized and undertaken by the program.

5.2.4 While some intervenors expressed concern with the survey design, they supported increasing the tolerance level on the grounds that it may lessen the administrative burden of the program. It was also suggested that the sharp increase in commodity prices since the implementation of the $35 level justified a change. Indeed, some intervenors argued that the level of the tolerance band should be higher than that sought by the Company, given the higher prevailing commodity price level.

5.3 BOARD FINDINGS

5.3.1 The Board notes that there was no opposition to the raising of the threshold per se, and approves the changes applied for with respect to the adoption of the $75 action level. The issues raised by those intervenors which oppose the program in whole are addressed in the next section.

5.4 THE TRANSITION OF THE PROGRAM TO DATABASE FORMAT

5.4.1 Enbridge submitted that since the risk management database will be placed in service by the end of 2005, it is appropriate to close all amounts spent on the project to rate base by the end of the year. Enbridge noted that the cost to convert the functionality of the model from a spreadsheet to a database format is estimated at $930,000.

5.4.2 Enbridge's proposal to include these costs in rate base led to the examination of the purpose and effectiveness of the overall risk management program and concerns with respect to duplication of functionality within the context of the Quarterly Rate Adjustment Mechanism ("QRAM"), the Purchase Gas Variance Account ("PGVA") and the equal billing program.

5.4.3 Some intervenors argued for the discontinuation of the risk management program and argued that it would be inappropriate to include the $930,000 in the 2006 opening balance for rate base. Enbridge argued that the issue was beyond the scope of this proceeding, insofar as the termination of the program did not appear on the Issues List, nor did any intervenor take the appropriate steps to include it on the Issues List.

5.5 BOARD FINDINGS

5.5.1 The Board has never previously focused its attention on the specific expenditures made to transition the program to the proposed database format. Enbridge made this transition without specific Board approval or direction. Its evidence that program administration had become unwieldy and unnecessarily complex was not challenged by those intervenors who opposed the Company's proposal. They directed their attention to the fundamental utility and advisability of the program as a whole.

5.5.2 Some intervenors strongly supported the risk management program, seeing it as a measure of protection, especially for low-income consumers, whose tolerance for price volatility was suggested to be less than that of other customer groups. They argued that many consumers, particularly low-income consumers, are vulnerable to steep price fluctuations, especially in an environment where there seems to be a generally upward tendency in commodity prices.

5.5.3 On the other hand, others are strongly opposed to the program, and regard the expansion of the actionable volatility level to $75 as tinkering with a program that should be eliminated.

5.5.4 Energy Probe, supported by CME, IGUA and the retail gas marketers, opposed the continuation of the risk management program. Energy Probe presented evidence by Mr. Adams, its Executive Director, which focused on two points:

- Given that the program is designed merely to smooth the impacts of market prices of the commodity, and not to lower them, it is of no real value to consumers. The "real" price will always emerge sooner or later, and consumers are not served by the illusion that the market price is actually being affected by the hedging activities of the utility.

- There is value in ensuring that consumers have direct experience of the actual price of the commodity that they consume. Any softening of that experience through hedging activities obscures the market price signal. Consumers are best served when they receive an accurate and un-hedged price signal from the market because they can vary consumption according to such signals.

5.5.5 This last concern motivated the retail gas marketers to oppose the program and any increased spending associated with it. In their view, the smoothing of price volatility sends inaccurate signals to the consumer, and improperly undermines the attraction of their fixed-price offerings in the marketplace. The dominant position of Enbridge which derives from its standard service supply monopoly is, in their view, exacerbated by the smoothing of commodity price fluctuations. They argued that the transparency of the price is an important element in their competitive environment. They contended that they are operating at a competitive disadvantage to the extent that the risk management program blurs that transparency.

5.5.6 An important part of the background to this issue is the existence of the Quarterly Price Adjustment Mechanism ("QRAM"). Some form of QRAM is applied to all privately held gas distribution utilities in Ontario, including Enbridge. While there are important differences in the respective methodologies, they share the effect of moderating and smoothing anticipated commodity price fluctuations. As part of the Natural Gas Forum, the Board expects to consider the standardization of QRAM methodology across all utilities.

5.5.7 As part of the QRAM process, the Board also provides for the maintenance of and disposal of the Purchased Gas Variance Account. This account captures the difference between the Company's projected cost of system gas and the actual cost. Its clearance also has the effect of smoothing commodity price fluctuations, insofar as the clearance of the account is distant in time from market purchases.

5.5.8 Finally, the Board notes the availability of equal billing plans for most residential customers. Such plans also have inherent smoothing effects, given that customers pay an averaged monthly amount which is subject to a true-up at or near the year end.

5.5.9 All of which is to say that in its implementation of the QRAM, its approach to the PGVA and the existence of equal billing plans, the Board accepts the principle that some form of price smoothing is an appropriate consumer protection measure. It is also important to emphasize that no matter what smoothing techniques are employed, the most that can be hoped for is a reduction in volatility, not an overall reduction in the price of the commodity over time. Subject to possible generational anomalies, consumers, both large and small, will pay the full burden of the market price for the commodity, sooner or later.

5.5.10 The question that remains is the extent to which Enbridge's risk management program is redundant or represents a useful and cost effective tool to reduce consumer price volatility in a fair and reasonable way. The Company provided evidence which seemed to show that its hedging activity smoothed its experience of commodity price fluctuations. No evidence has been provided that demonstrates whether the hedging activity had a material effect on the volatility experienced by customers, given the effects of QRAM, the PGVA, and equal billing programs over the same period. If hedging activity has no material effect on the volatility experienced by customers, then it may be that the risk management program is not required.

5.5.11 Accordingly, the Board directs Enbridge to prepare for consideration in its next rates case evidence which demonstrates the extent to which the Company's hedging activities in 2003, 2004, and 2005 would have resulted in reductions in volatility for its customers, had it applied the proposed $75 action level.

5.5.12 Enbridge asserted that the continuation of the program is not an issue in this proceeding, and that the intervenors who argued for its elimination in this case are seeking an outcome that is simply beyond the Board's scope. This point of view was supported by several intervenors that support the program, if not the specific changes sought by the Company.

5.5.13 While it is unnecessary to decide this point for the purposes of this Decision, given the Board's disposition of the issue in this case, the Board considers it appropriate to address the underlying proposition. The Board considers that where convincing evidence is presented which leads to a compelling conclusion that a program does not provide value to ratepayers, it is always open to the Board to disallow any further spending on the program, whether or not the issue falls within the four corners of an issue on the Issues List. The Board would clearly have a duty to exercise this discretion only in the most compelling case and never without offering the Company an appropriate opportunity to rebut the evidence supporting the termination of the program. The overriding principle is that in a rates case the Board always retains jurisdiction to make whatever order is necessary to establish just and reasonable rates. Requiring ratepayers to pay for operations that have been demonstrated to be without value to ratepayers is unreasonable.

5.5.14 The Board notes that Energy Probe's evidence was subject to all of the normal procedures. The Company cannot assert that it had no notice of, or was unduly prejudiced by the Energy Probe evidence. If the Company intended to insist that the termination of the program was out of scope, it should have done so when first presented with the Energy Probe evidence urging that outcome.

5.5.15 The Board will not order the discontinuation of the program for the Test Year. The Board is, however, concerned about the fundamental appropriateness of the program, and accordingly has directed the Company to develop evidence respecting its effects, as detailed above. In the interim, pending the Board's consideration of that evidence in the next rates case, the sums expended to upgrade the Program to a database format will not be released to rate base. Instead, the relevant sum, thought to be approximately $930,000, shall be placed in a deferral account exclusive to this purpose. The deferral account will be disposed of according to the Board's finding in the next rates case.

average customer could understand.[160] In fact, notwithstanding that the questions in the survey related to risk management instruments did not mention risk management terminology (such as caps, collars and swaps), they were nonetheless able to convey concepts such that the average consumer could understand and comment.[161] In short, the Company believes that the customer survey, which was undertaken in accordance with the Board's decision in RP-2003-0203, provides a valuable and updated perspective on the $35 price volatility tolerance level identified in the surveys undertaken in 1994 and 1995 and is more relevant than earlier studies that were undertaken in different market environments with much lower gas prices.[162]

The results of the customer survey indicate that the Company's emphasis on reducing price volatility and the approach to managing that price volatility is supported by its customers. Additionally, customers have indicated their acceptance to have the commodity portion of their annual natural gas bill fluctuate by a maximum of $75. Given the survey results, the Company requests Board approval to increase the price volatility tolerance band from the current $35 to $75.[163]

C. Evidence of Energy Probe

On June 23, 2005, Energy Probe submitted evidence in this proceeding titled "Risk Managed System Gas: The Case Against", authored by Tom Adams.[164] CCC's counsel described it as a "root and branch critique of the value of the risk management program at Enbridge".[165] Mr. Adams confirmed on cross-examination that he is not an expert on risk management, nor on customer survey design or implementation, which are among the main topics that he addresses in his paper.[166]

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[160] 5 Tr. 120-121; Ex. I-3-17

[161] Ex A3-3-1 Attachment, pp 41-45 – Questions 14 to 19

[162] 5 Tr. 115

[163] Ex. A3-3-1, p 9

[164] Ex. L8-2

[165] 5 Tr. 65

[166] 38 Tr. 119

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In short, Energy Probe's position paper urges the Board to order the discontinuance of the Company's Risk Management Program. This is not on the Issues List for this proceeding, nor did Energy Probe take any steps to have that issue included on the Issues List, either at Issues Day or subsequently. As Mr. Adams acknowledged on cross-examination, the listed issues for this proceeding relate to the implementation of the RiskAdvisory report and the customer survey.[167] According to Mr. Adams, the link between the Issues List and Energy Probe's position is that "[t]he issues list contains with it – within it an assumption that the utility will continue its risk management program".[168] Interestingly, however, as Mr. Adams stated in his testimony, Energy Probe did not challenge the existence or prudence of the Company's risk management program in the F2005 rate case, when there was a more wholesale evaluation of the risk management program than in this case, because "[t]he argument as to the discontinuance of the plan we believe to have been off the issues list in that proceeding".[169] Presumably, however, the same assumption that the Company would continue its risk management program was also part of the Company's F2005 rate case. Given that the question of whether the Company should continue its risk management program is not an issue in this proceeding, the Company urges that little if any weight should be given to Energy Probe's evidence.

If the question of whether the Company ought to continue its risk management program is not at issue in this proceeding, then Energy Probe is actually supportive of the relief sought by the Company. This can be seen in the final sentence of Energy Probe's submission which reads:

> In the alternative, if the Board is not moved to order the discontinuance of risk management entirely, the threshold target for the minimum PGVA balance be should raised substantially, at least to $75 per customer, although $100 would be better and $200 better still.[170]

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[167] 38 Tr. 165

[168] *Ibid*

[169] 38 Tr. 123; see also 38 Tr. 159

[170] Ex. L8-2, p 12

In cross-examination, Mr. Adams confirmed that Energy Probe does support raising the threshold.[171]

Notwithstanding the fact that Energy Probe's position paper does not appear to bear upon matters at issue in this proceeding, the Company has several comments to make in response.

First, in respect of the overall argument by Energy Probe that the Risk Management Program should be discontinued, the Company has the following responses: (i) the Board has recently confirmed in both the RP-2003-0203 and RP-2003-0063 (Union Gas F2004 Rates Case) Decisions that gas commodity risk management programs are beneficial[172]; (ii) Energy Probe does not rely on any change in circumstances from those existing at the time of recent Board decisions in support of its position that risk management should now be discontinued[173]; (iii) every gas utility in Canada, except for one, has a commodity risk management program[174]; and (iv) in contrast to the Company's survey results, Energy Probe presents no recent evidence that customers do not want commodity risk management.[175] To the contrary, Energy Probe acknowledges that "all customers would like to have no price volatility"[176] and that there are consumer groups who support the continuation of risk management.[177]

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[171] 38 Tr. 152 and 166-167

[172] Ex. K38.2, Tabs 2 and 3: RP-2003-0203, Decision with Reasons, November 1, 2004, para. 4.3.4; and RP-2003-0063, Decision with Reasons, March 18, 2004, p 17

[173] 38 Tr. 161-163: while Mr. Adams asserts that it is only in this case that the Company is making it clear that "customers should not anticipate sustained benefits, in terms of lower prices, over time", the fact is that the Company made this clear in the F2005 case, as seen in para. 4.3.8 of the Board's decision which approves the proposal to make reducing price volatility the primary objective of the Company's risk management program (as opposed to a joint objective along with benefiting and profiting from price declines)

[174] 38 Tr. 121 and 171

[175] 38 Tr. 169

[176] 38 Tr. 155

[177] 38 Tr 172

Second, the following testimony by Mr. Rubino answers Energy Probe's suggestion that "risk management provides no sustained value to ratepayers"[178]:

> We disagree strongly with that statement. Our view is that, given that customers have indicated, through this survey, through the survey that was done ten years ago, that they have a desire for the company to take actions to mitigate some of their exposure to volatility; the customers value the actions that the company is taking. And an ongoing risk-management program provides that sustained value. Whether it's a pure economic value, in terms of, you know, the program winning or losing in a given year, the sustained value is that there has been mitigation of volatility, which is what customers have indicated they are looking for the company to do.[179]

Finally, in response to the suggestion that ratepayers are burdened by the costs of the Company's Risk Management Program, the Company reiterates that the costs are minimal. Significantly, however, the benefits are substantial. As seen in the response to Undertaking J5.8, over the years from 2001 to 2004, the Company's Risk Management Program reduced price volatility of the Company's gas purchasing by an average of 61%.[180] It defies belief to assert, as Mr. Adams does, that none of this decreased volatility is felt by system gas customers.[181] Moreover, while this is not the goal of the Company's Risk Management Program, in the years from 1996 to 2004, the overall reduction in gas purchase costs as a result of the Program, which is directly passed on to customers, was $59.1 million.[182] This certainly does not represent a cost burden to ratepayers.

D. Conclusion

The Company respectfully submits that, based upon its prefiled evidence, including the customer survey, and its testimony in this proceeding, it has provided a solid evidentiary basis for Board approval to increase the price volatility tolerance band from the current $35 to $75.

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[178] Ex. L-8-2, p 11

[179] 5 Tr. 71-72

[180] Ex. J5.8, which attaches and updates Ex. I-1-18 from the RP-2002-0203 proceeding; see also 5 Tr. 67 and 38 Tr. 146-148

[181] 38 Tr. 146-148

[182] Ex. J5.6

Given the nature of the issues actually before the Board in respect of risk management, and in particular the fact that the potential discontinuance of risk management activities is not at issue in this proceeding, the Company respectfully submits that no relief ought to be granted in response to Energy Probe's evidence and submissions.

7. RATE BASE

Rate Base is the subject matter of Issues 8.1 through 8.4 of the Issues List, which are specifically identified as follows:

> 8.1 Capital Budget for the 2006 Test Year including capitalized O&M expenses
>
> 8.2 Information Technology Capital Budget including Energy Transaction, Reporting, Accounting and Contracting (EnTrac), and Meter Management and Large Volume Meter Data Processing (EnMar) projects
>
> 8.3 Appropriateness of the capital budget "placeholder" for power generation project RFPs
>
> 8.4 Appropriateness of the capital budget for System Improvements and upgrades, including the budget increases in system expansion and reinforcement projects and the Accelerated Bare Steel and Cast Iron Replacement Program

None of these issues were resolved during the Settlement Conference. As a result, together with its extensive prefiled evidence, the Company also provided three witness panels during the hearing to speak to different aspects of this broad subject matter: a *policy panel* (including the Company's President) to speak to the underlying rationale of the Test Year capital budget; a *customer attachment-related panel* to address system expansion and customer attachments (and in that context, the issues around prospective gas-fired electricity generation customers); and a *system reinforcement-related panel* to address the remainder of the capital and rate base issues (including the information technology capital budget and the appropriateness of the Company's reinforcement projects, and accelerated bare steel and cast iron replacement program).

you want to ask to help the customers get their -- get a frame of reference, in terms of what's being talked about. But in terms of trying to do a direct comparison of a survey that was done ten years ago, and try to establish historical trends, that wasn't one of our objectives.

MR. ADAMS: In the -- the results of this survey in 1995, in response to the clear question "do you want the lowest price, as opposed to a higher, but stable, price" -- the response to that question, on a scale of 1 through 7, was that 73 percent - and I'm reading from the conclusions of the Compass study, page 12 - on a scale of 1 through 7, 73 percent of the residential, and 70 percent of the industrial, commercial and apartment customers, responded believing paying the lowest price is important.

Of these, 35 percent, in each group, gave a score of 7, the highest score -- highest point. Among residential -- the residential sample, 11 percent are neutral, and 15 percent say it's not important compared to a higher, but stable, price.

I suggest to you that the only evidence that we have on the record before the Board as to customer views - specifically, on whether they want lowest price, as opposed to a higher, but stable - is the answer to that question that was asked in 1995.

Do you object to that observation?

MR. CHARLESON: Well, I think, again, looking back to the question from this survey that Mr. Rubino pointed to earlier, on page 29 of the evidence, it does provide, in my opinion, an updated view of that. While it's not an identical question, it gets to the same principles, the same concepts. And so, as a result, I would say that this is something that does provide an updated perspective on that, and is more current and more relevant than a ten-year-old survey, when we were operating in a much different market environment.

MR. RUBINO: The headline on that page 29 of the attachment, indicates:

"'It is more important to maintain a steady price than to obtain the lowest price', more than 6 in 10 -- 60 percent small commercial customers, somewhat more than residential, 55%."

MR. ADAMS: I see the headline, but that's not -- the headline was not presented to the customer -- to the --

MR. RUBINO: No.

MR. ADAMS: -- participants in the survey.

MR. RUBINO: The question was -- in very small type at the bottom --

MR. ADAMS: Yes. And that question --nowhere does it indicate that the steady price is higher.

MR. CHARLESON: You're right.

MR. ADAMS: The conclusion in the 1995 study, in the paragraph on page 12, is as follows:

"Hence, there is clear support by well over half the respondents in all segments for the concept of taking on the risk of higher prices by managing purchasing gas at floating prices in

"... order to gain the opportunity to achieve lower prices."

And that, really -- at the time, that was the objective of the program; would you agree, Mr. Rubino?

MR. RUBINO: That's correct. It was, at that time.

MR. ADAMS: The conclusion -- the final statement is:

"This is more important than average among residential respondents with lower incomes and women."

Then it goes on to say:

"There are not significant differences between groups of the ICA sample."

Just, specifically, with regard to this last conclusion, where the previous study identified low income groups and women -- the views of low-income individuals and women, separately, do I understand correctly that was not done in the Ipsos-Reid study?

MR. CHARLESON: There was some segmentation done within the study. However, the observations that we received, in terms of the reporting that was done for us by Ipsos-Reid, and the compilation of the report, didn't get into that degree of segmentation because, again, given that we were looking at something for a total customer base, we had responses that we believed, and that our research group indicated to us, were representative of the entire customer base. You know, it's our belief that we're trying to put in place a program, and put in place measures, that meet the needs of all customers, not targeted groups.

MR. ADAMS: So is it fair to say that the only information we have in front of the Board, with respect to the views of low-income individuals, with respect to their desire for paying a premium to achieve price stability, is that they are among the least favourable to this, and that is lower than the 73 percent average amongst residential customers who are not in favour of paying the premium --

MR. CHARLESON: I'm not --

MR. ADAMS: -- is that fair?

MR. CHARLESON: No, I don't know if that is fair, because I don't follow what evidence you're pointing to, to reach that conclusion.

MR. ADAMS: From the 1995 study --

MR. CHARLESON: That's --

MR. ADAMS: -- the section I just read to you.

MR. CHARLESON: Yes, I would say that's the only information available within the record in this proceeding, but again, recognizing it's a ten-year-old study, and reiterating that our focus is on all customer groups, and not specific segments.

MR. ADAMS: Thank you. Now, with respect to direct-purchase customers surveyed, I looked in the methodology discussion, and did not find the survey attempted to confirm that the respondent to the survey matched the signature on the applicable marketer contract; is that a fair reading?

MR. CHARLESON: Yes, I would say that is a fair reading. And it may be difficult to assess, given that a large number of customers still don't realize they're on direct purchase --

MR. ADAMS: Right.

MR. CHARLESON: -- so they may not know who signed the contract.

MR. ADAMS: Right. It's -- apparently, 58 percent of your customers aren't sure whether -- 58 percent of the customers that are on direct purchase don't know that they're on direct purchase, according to the survey results?

MR. CHARLESON: That sounds about the right number.

MR. RUBINO: Subject to check.

MR. CHARLESON: And that's something that we have seen through, I think, through a few surveys we've done over the last couple of years. That number has been consistently around 60 percent.

MR. ADAMS: On the issue of including direct-purchase customers in the survey, I note that, in the Natural Gas Forum, EGD expressed the view that it ought to be permitted to maintain a critical mass of system-gas customers. Was that desire by your company one of the reasons why direct purchase-customers were included in the sample?

MR. CHARLESON: No, that didn't play a factor in our sampling, at all.

MR. ADAMS: The page that Mr. Rubino just turned us to, from the Ipsos-Reid study, page 29 --

MR. RUBINO: Yes?

MR. ADAMS: Specifically, with regard to --

MR. RUBINO: Yes.

MR. ADAMS: The system gas actual results, where 51 percent of the customers are in favour of steady versus 47 lowest and 2 percent don't know, is the result there statistically significant? Can we statistically determine that system gas actuals are in favour of steady, or not?

[Witness panel confers]

MR. RUBINO: Yes. The answer is yes. I made a point of asking our business and intelligence group -- sorry, research and business intelligence group, and then, in turn, them asking the Ipsos-Reid people, and they indicated that it was.

MR. ADAMS: That is statistically significant?

MR. RUBINO: Yes.

MR. ADAMS: I understood that the errors bounds in the study were 3 percent.

MR. RUBINO: Three-and-a-half.

MR. CHARLESON: Perhaps there is some confusion between statistically significant and statistically valid. So it is statistically valid sample, statistically valid sample size. In terms of significant, you're correct, there is a margin of error in the survey, I believe, of plus or minus 3 percent.

MR. ADAMS: Right.

MR. CHARLESON: So, again, to say that the majority of customers are -- of system gas actual customers are in favour of steady versus -- as compared to lowest, there is the potential that given the margin of error, that it overlaps.

MR. ADAMS: Yes, thank you. Just before I leave this area, one last question. I observed at several points indications of significant customer confusion, like, for example, a relatively small number of direct purchase customers knowing that they're on direct purchase.

In light of this indication that customers really don't have a deep understanding of how the gas markets are serving them, do you have any concerns about the reasonableness of asking customers about the relative preference for caps versus collars versus swaps? Caps and collars might sound like a clothing choice to most customers.

MR. CHARLESON: I think definitely we had concerns with how you go about asking customers about, you know, caps, collars, swaps, because it's -- again, even until I got responsibility in these areas, I would have been confused by that. But that was one of the key elements in designing the survey, was having the discussions with Ipsos-Reid and with risk advisory to try to craft questions in a manner that would put those instruments into terms that the average consumer would be able to relate to and to understand.

MR. RUBINO: Yes. And we spent -- I spent a considerable amount of time. It's question 14 in the survey, and it's repeated in response to CME Interrogatory Number 17 in this proceeding.

MR. ADAMS: Mm-hmm.

MR. RUBINO: I would suggest if you read through those, it doesn't really matter what they're called, swaps, caps or collars. It was the concept we were trying to get across, and, again, realizing it was a telephone survey in the evening, but we -- we believe that we succeeded in accurately describing conceptually what each of those three hedge instruments attempts to achieve.

MR. ADAMS: When we looked at the results that arose from asking their preferences with regard to the caps, collars or swaps, my reading of it is that the opinion appears to be fairly evenly split there.

MR. CHARLESON: Yes. That was our view, as well.

MR. RUBINO: It was our view, as well.

MR. ADAMS: So one possible explanation for this is simply that the customers are throwing darts at the answer and politely responding with, you know, something that they thought might entertain the survey questioner.

MR. CHARLESON: Or the possible other outcome is that they understood the question and they responded based on what their preference was.

MR. ADAMS: Right. So the same people that didn't know whether they were on system gas or direct purchase were providing a deeper understanding of financial hedging instruments; is your suggestion?

MR. CHARLESON: Yes, because, again, I think -- I don't want to get argumentative, but I think the -- for people to understand whether they're on system gas or direct purchase requires them to, one, either recall having entered into a contract, being -- paid particular attention to their bill to understand who their supply is based on what is indicated on their bill.

To have -- so that's not something top of mind, though. When I open my bill, I don't look to the middle to make sure that I am still getting the system gas rate or that I am still on system supply.

But hearing the question, it is put in terms that are, you know, very general and very generic in nature and very common terminology; doesn't require your having to recall, What did I see on my bill, or what did I -- or what did I sign up for at the door or online.

So I think there is a great difference, in terms of the ability or the -- for customers to respond appropriately to the questions.

MR. ADAMS: Okay. Thank you for that. I want to turn to the question of hedgible volumes, and the interrogatories I'm going to refer to are CME 14 and page 3 of VECC IR 28, part F, if you would.

MS. NOWINA: Is that part of your package, Mr. Adams?

MR. ADAMS: Unfortunately not. This is where I --

MS. NOWINA: Okay. Just give us a moment.

MR. ADAMS: -- was incomplete.

MR. CHARLESON: Sorry, the second one for VECC was 14?

MR. ADAMS: VECC 28, CME 14.

MR. CHARLESON: Okay.

MR. ADAMS: Now, I am really perplexed about how you calculate hedgible volumes, and I just want to get this cleared up.

If we -- if we look to CME 14, you have a calculation that you present there. It's lowest number degree days in the last ten years, multiplied by current use per degree day, multiplied by current number of customers, multiplied by the lower of -- the lowest level of participation in system gas in the last ten years or the company's view of system gas participation in the forecast period.

MR. RUBINO: That's correct.

MR. ADAMS: Okay. So that multiplies out to some very large number.

MR. RUBINO: Correct.

MR. ADAMS: Probably in the millions?

MR. RUBINO: This past year it was approximately 120 Bcf.

MR. ADAMS: Okay. Now, the one piece of it that I need some help with, how does -- how many customers are going to be on system gas next year?

MR. RUBINO: Well, there will be -- internally, we'll have an estimate of what that number will be, based on historical information.

MR. CHARLESON: Right now we look at that being, I'd say, somewhere between, say, 950,000 and just over a million, say, just -- right now, we're seeing it around 60 percent of our customers are on system gas.

MR. ADAMS: The fraction of customers on system gas bounces around; right?

MR. CHARLESON: It moves, but over the past number of years, and I think if you -- again, I'm trying to -- there's an interrogatory response where we provided --

MR. ADAMS: Energy Probe 95?

MR. CHARLESON: Ninety-five. So if we look at -- which is Exhibit I, tab 8, schedule 95. I think if you look back through there, what we've seen is, say, over the last seven years, other than, say, 2001 and 2002 when we saw the initial -- say, the price spike coming out of the winter, say, December 2000, the percentage of customers on system gas or the distribution between system gas and direct purchase has remained fairly stable.

So it's almost like we view those two years as an exception, and then it settled back into a relatively steady pattern and we're seeing that pattern continue.

So it will fluctuate, but I think it fluctuates within -- at this point, at least, within a relatively narrow band, recognizing that you may have a couple of years where there will be exceptions.

MR. ADAMS: Yes. So over the period of years shown here, which is eight years, of those years, five of them -- I'm sorry, six of those eight, it's around -- between 36 percent and 40 percent. But then, two of those years, it's over 45; right?

MR. CHARLESON: Yes, that's correct.

MR. ADAMS: And so you're saying that you're certain that next year, 2006, it will be at the -- around the figures that it's been in six of these eight years.

MR. CHARLESON: I can't say I'm certain. It --

nothing is certain. Given the price run-ups that we have seen over the past couple of months, we may see a similar response from customers to the direct-purchase markets that we saw back in 2000, 2001. You know, that remains to be seen.

But if we look at the formula, again, that's used within -- that's identified in the CME response, it would be the lowest level of participation in system gas in the last ten years. Or, our view on system -- so if our view on participation in system-gas was that it was going to stay where if is today, around 60 percent, the number that we would end up using would be the 52 percent --

MR. RUBINO: It's the lower of --

MR. CHARLESON: -- the lower of. So the 2002 number, where we had 52.6 percent on system gas, that would be the lower number that gets used.

MR. RUBINO: It's intentionally conservative. The purpose of this calculation is to ensure that the company is not over-hedged. We have no interest in hedging more volumes than are required. And that's the reason it's so conservative --

MR. ADAMS: Okay. So --

MR. RUBINO: -- including the lowest number of degree-days in the last ten years.

MR. ADAMS: When you're calculating the volumes eligible to be hedged, the formula that tells you how many -- what the volumes are, available to be hedged, makes no reference to the volume currently hedged; right?

MR. CHARLESON: Correct.

MR. RUBINO: Correct. That's correct.

MR. CHARLESON: Other than, if you were, you know -- as you use this formula, going forward, there's obviously going to be a relationship between what you're currently hedged -- the volumes that are available to currently hedge and what you're able to do in the future, because they're all based on the same formula, going forward.

MR. ADAMS: I -- that's not obvious to me. The formula is the formula.

MR. CHARLESON: Yes.

MR. ADAMS: It makes no reference to the volume currently hedged. If you had, you know, 100 million hedged, and the formula generates a figure of 120 million eligible to be hedged, are you going to add to that hedging quantity the next year?

MR. RUBINO: No. The --

MR. ADAMS: Where is that explained in your -- in --

MR. RUBINO: Well, this calculation is completed at the beginning of any given fiscal year. And that's the amount of volume that will be hedged over the next 12 months. It's what is available for hedging.

MR. CHARLESON: So I would agree with your comment that there isn't necessarily a direct link between what is available for hedging and what actually gets hedged. But, in terms of what's available for hedging, you would expect there to be a relatively close relationship from one year to the next, given that a number of these factors look back at numbers over the last ten years.

MR. ADAMS: Okay. Thank you for that.

Now, if we flip forward to VECC 28, at page 3, the company has asked a similar question in part F:

> "Please explain the extent to which the company will be in a hedgible position, if the $75 tolerance level is accepted. In effect, please indicate the volume level that is currently hedged and, if the higher tolerance level is accepted, how much that level of hedged volumes would change."

That was the question.

And --

MR. CHARLESON: I'm just -- sorry to interrupt, but just to be clear. I think, at the beginning, when you were reading the first line of that, you just indicated the extent in which the company will be in a "hedgible position", where it was actually a "lower hedgible position."

MR. ADAMS: A "lower hedgible position." I --

MR. CHARLESON: Just for the record to be clear.

MR. ADAMS: I'm sorry.

Now, we look to the reply. The last sentence of that reply indicates:

> "The company cannot, however, predict future price volatility, and, hence, cannot predict the associated volumes that may be hedged."

Right? Do you see that?

MR. RUBINO: It reads that -- you read it correctly.

MR. ADAMS: What -- my question is, what relationship does future price volatility have with respect to the formula that tells us the associated volumes that may be hedged?

MR. RUBINO: Well --

MR. CHARLESON: I think, in looking at that -- given that -- with the higher tolerance band and the potential of being in a hedgible position less often, that could lower the extent to which -- that you're -- the amount of -- how frequently you will be in a hedgible position, which can lead to you hedging less often. If you were to go through the whole year and you never exceed that band -- say, the band always -- say, $60 is the maximum that you ever see, well, you won't have hedged any volumes. With a $35 band, you would have exceeded that band, and so you would have hedged more volumes.

So there is the potential that, given the frequency that you may be in a hedgible position, it could have an impact on the total volumes hedged.

MR. ADAMS: I'm going to have to read the transcript to figure that out.

MR. CHARLESON: I hope I was clear enough for you.

MR. ADAMS: I'm going to turn to my last area of questions.

Okay. Now, Mr. Charleson, when you were discussing with the previous questioners your company's position with respect to transactional services, you drew attention to the necessity, in your view, of incentives for management. And I want you to turn you to a couple of transcript references. On page 88, volume 2, you said:

"I think as you look at the -- say, the risks and the uncertainties regarding the level of revenue, the level of gross margin, you want to ensure that there's still an appropriate incentive to attract management attention."

Later on in the transcript, you made a similar comment to Mr. De Vellis. And if the revenue -- sorry, this is Mr. De Vellis speaking:

"And if the revenues --

MR. CHARLESON: Perhaps, you could point us to the specific reference.

MR. ADAMS: Oh, I'm sorry. Page 92 - sorry - line 16 and following. Mr. De Vellis asked:

"And if the revenue -- sorry, the percentage of TS revenue that go to the company was, say, 10 percent rather than 50 percent, would these employees do their job any differently?"

Your response:

"Those employees -- I wouldn't expect them to do their job any differently. Again -- because, again, their focus is taking the assets that have been made available to them and trying to optimize the value that they're able to get. The concern that we have is, is the more management attention, management focus, also the manner in which we may look to manage other assets. So there's other parts of our -- of the way we manage our supply portfolio, the way we manage our -- the overall operation of our system, that may create opportunities for transactional services for these people to go and optimize. And that is more where our concern lies, from a sharing-mechanism perspective, and the management attention is: is there an incentive that these people, that aren't directly involved in the TS function, have, to try to ensure that there is an appropriate -- that there is that focus to try to provide the opportunities that make assets available for that person to then go and to optimize it. "

Now on the subject of TS, you testified that much richer incentives than those previously approved by the Board as applicable to TS are required to "get management's attention."

The utility has taken a similar view with respect to DSM, wherein its filing in this case, the proposed formula for SSM would yield a much higher ratio of return to the utility.

My question is this: With respect to risk management, your evidence is that there is a high level of top senior management spending a lot of time making sure that risk management is optimized, but it is all pro bono work, flow-through.

MR. CHARLESON: I guess there's a few aspects and a few characterizations that you have made in your statements there that I want to just try to address first.

First off, I can't speak to DSM and what is being requested there. I'm not the -- definitely not the expert in that area and not a witness on that evidence.

In terms of our transactional services, the request for the change to the sharing mechanism isn't necessarily a request for a much richer -- I forget the exact, precise words you used, but we're looking for what we believe is a fair sharing, given some of the uncertainties, and it may still result in us receiving a lower incentive than what we've had in the past, depending on what happens with transactional services revenues.

In terms of a significant amount of management attention, a significant amount of time, I think, as we've indicated, we hold risk management -- I agree there is attention from the senior levels within the organization towards risk management. We talk about one meeting a month. Those meetings are typically an hour or less in duration.

So, yes, the attention is there. Whether it's a significant amount of time, given the amount of time that our senior management would put in over the course of a month, I'm not sure that I would classify one hour even of -- assess another hour's preparation or discussion around risk management as being significant in the grand scheme.

You also indicated that, I think in your -- when you talked about significant time in terms of kind of the optimizing on the risk management. Again, that is not the objective of the program. The objective of the program is to mitigate volatility.

So I'm not sure if I have addressed your comments or if there is a specific question beyond that that you would like me to answer.

MR. ADAMS: What is the incentive driving senior management's attention to risk management?

MR. CHARLESON: Risk management is something that we see as being -- as related to more of a core activity of system supply. We have, as we've indicated, potentially around a million customers that rely on us for supplying their gas.

Those customers and -- well, all customers have indicated that they believe it is appropriate and that they would like to see the utility taking actions to mitigate that volatility. And, as a result, we have a risk-management program. That risk-management program, which has been approved by the Board, is in place to try to execute those customer wishes and what we see as being part of our core supply function.

And, also, given the dollars associated, the value of the transactions that come into play, you know, when we're looking this year, we have the potential -- heading towards this winter, there's the potential we could be looking at the value of the premiums that we pay alone in our caps being in the order of $40 million.

So there's significant costs that may be incurred in putting these transactions in place. Obviously, you don't know what the end result -- you know, you may have paid $40 million and it may end up having reduced costs by 42 or $45 million. You don't know what the outcome of those transactions are going to be, but given that there is that outlay or those costs that are incurred, it's something that is viewed as core and something that requires that attention.

MR. ADAMS: If any intervenors came forward and said that the utility ought to be accountable for ensuring lower gas costs by virtue of your risk-management program, you would resist that; right?

MR. CHARLESON: Yes. We would be very concerned with that, because I think as Risk Advisory indicated last year, for anybody to expect to beat the market on an ongoing basis is either very lucky or fooling themselves.

MR. RUBINO: "Unreasonable" was the word they used.

MR. CHARLESON: Yes. I paraphrased.

MR. ADAMS: Now, I will just close off with a couple of clean-up questions. In your evidence in-chief and your response to Mr. Warren, you commented that risk management had a different impact on the customer than equalization, bill equalization. Do you remember that discussion?

MR. CHARLESON: Yes, I do.

MR. ADAMS: Can you explain to me what the difference is, again?

MR. CHARLESON: Again, when we look at risk management

-- risk management is meant to mitigate the volatility in the prices that a customer will experience. But, ultimately, they're going to pay -- so it's mitigating the total price that they will pay for their commodity costs.

So, again, if we look at experience over the past few years, in total, you might have seen in one year a $20 million lower total commodity cost to system gas customers because of risk-management activities. So over a 12-month period, system gas customers will have paid $20 million less.

MR. ADAMS: What year was that?

MR. CHARLESON: Again --

MR. ADAMS: Energy Probe 93.

MR. CHARLESON: I guess I should be more careful in terms of just putting examples out there. Again, within Energy Probe 93, it shows that between 2004 and 2005 that the costs have actually been slightly higher.

MR. ADAMS: By 4- and 12 dollars.

MR. CHARLESON: By 4- and 12 dollars. But if we were to look back in the last proceeding, we also showed, in 2003, where the -- this was in CME Interrogatory No. 20, that the gain or the savings resulting from risk management was $23 million. So, again, just -- it can go one way or the other, but -- so for the use of my example, I chose a year where there was a savings resulting from the risk management.

So over the course of the years, system gas customers will have paid $23 million less than if there was no risk management program. If there was no risk management program and customers, instead, relied on equal billing to manage the volatility or to mitigate volatility, over the course of the year, it's true month over month what they pay will be smooth and there won't be dramatic fluctuations in there.

But at the end of the year, over the 12-month period, if all customers -- if all system gas customers were on equal billing, they still would have paid the $23 million more. So it hasn't -- or in the case of a year where there was -- you know, where risk management ended up costing more, they would have paid less.

So it has the effect of smoothing the timing of when they made those payments, but it doesn't remove, say, the impact of volatile gas prices on the total commodity costs they're going to pay over an annual basis.

MR. ADAMS: Mr. Charleson, that's looking at an annual basis. What about a customer over the long term, customers who buy gas on the long term? You have a house; you buy gas for 20, 30 years for the thing.

MR. CHARLESON: True.

MR. ADAMS: They're not expecting this risk management program to yield any benefits for that customer over a long-term period.

MR. CHARLESON: Correct.

MR. ADAMS: Whether they're on equal billing or not.

MR. CHARLESON: Yes, that's correct.

MR. ADAMS: So there is really no difference except the additional overheads. If you look at it on a long-term basis, the impact of your risk-management program is simply to increase the overhead costs borne by those system gas customers; right?

MR. CHARLESON: And if we look at the survey results it seems that it is something that customers have asked us -- or look for us to do. But, again, I can't disagree with the statement that you've made.

MR. ADAMS: Okay. The purpose of this -- let me just go back to the purpose of this expensive IT program you're putting in place, here. The IT program that it's replacing was something that was produced in-house, I assume --

MR. RUBINO: That's correct.

MR. ADAMS: -- by your own engineers -- your own staff?

MR. RUBINO: Our own staff.

MR. ADAMS: Now you're going to out -- to pay almost a million bucks for this new system. The benefits in the new system are primarily to protect the utility; right?

MR. CHARLESON: I would say it is to protect the utility ratepayer, because it helps us to administer the risk-management program, and ensure that we're executing the risk-management program in a manner that is consistent with what they desired, and in the manner that the Board has approved.

MR. ADAMS: If risk management -- if you guys had a rogue trader, or somebody that mismanaged this thing, and you came up with a big hit, there's a risk that the utility could get hit; right? We saw that with Central Gas Manitoba.

MR. CHARLESON: Yes, there is that risk.

MR. ADAMS: And so that risk needs to be managed prudently and carefully.

MR. CHARLESON: Yes. And perhaps that's why it receives the high level of management attention.

MR. ADAMS: Thank you.

Those are my questions.

MS. NOWINA: Thank you, Mr. Adams.

Mr. Dingwall, Miss DeMarco, can you give me a sense of how long your examination will take?

MR. DINGWALL: Madame, roughly half an hour, subject to negotiations with Ms. DeMarco, off the record, over the break.

MS. NOWINA: Ms. DeMarco?

MS. DeMARCO: I can guarantee that, come hick or come stick, we will be done by 4 o'clock today.

MS. NOWINA: Thank you. Even if we take a 15-minute break now?

MS. DeMARCO: Absolutely, Madam Chair.

MS. NOWINA: Let's take a 15-minute break, and we'll get back together at ten before the hour.

--- Recess taken at 2:35 p.m.

--- On resuming at 2:50 p.m.

MS. NOWINA: Please be seated. Mr. Dingwall, were you going to proceed next.

MR. O'LEARY: Madam Chair.

14. Good to its word, the Applicant has demonstrated that it just can't beat the market. And, unfortunately for the residential customers of Enbridge, recently it does not seem to be able to even get close. Data used in Table 1 below, with the exception of the right column and the bottom row, is drawn directly from Superior Energy Interrogatory #7[3].

Table 2

Year	EDG/Volume of Risk of Management Activity (m^3)	Cost of Risk Management – Purchases/Options (Gain/Loss) $Millions	Average AECO Spot Price of Gas Over Same Period ($C\$/10^3m^3$)	/U Impact of Risk Management on PGVA Price **
2006	**1,727,585***	**(110.0)***	**249.5***	**+0.66%***
2005	**2,041,077**	**19.0**	**303.0**	**-0.02%**
2004	**1,684,201**	**(4.3)**	**242.6**	**-0.05%**
2003	**1,262,802**	**23.4**	**239.4**	**-0.04%**
2002	**1,579,199**	**(40.8)**	**145.4**	**+0.76%**
2002-2006		**Net = (107.3)**		**+0.26%**

* as of Nov 2006; ** see Table 1, column Resulting Price Impact: Expressed As a % /U

The values in the column identified as "Impact of Risk Management on PGVA Price" represent the average impact of the risk management program on the PGVA reference price, as presented in Table 1, for each annual period and the overall five year period. /U

[3] Exhibit I/Tab 18/Sched. 7, p. 2, Response (a)

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ENERGY PROBE INTERROGATORY #19

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

The Evidence at D1/T4/S3, beginning at Page 8, Paragraph 22, describes the EBP as follows:

> As a plan that is available to all residential heating customers (with certain restrictions), the EBP is designed to ease the customer's bill payments over the course of the year by spreading higher monthly payments that the customer would be faced with during the winter months. While this does inherently reduce the volatility a customer experiences in their gas bill, the EBP is not intended to protect customer bills from natural gas price volatility and should not be compared to the Program. The EBP is a payment option available to all customers, while the Program applies only to customers on system supply.

a) At D1/T4/S3, on Page 3 of 14, at Paragraph 10, the Evidence states that the QRAM methodology was developed to achieve or accommodate eight principles, with any reference to reducing volatility conspicuously and clearly absent. Why does the Applicant believe that the EBP should not be compared to the Risk Management Program, when both can operate with the QRAM independently of the other?

b) Please provide a table showing the incremental costs, both O&M and capital, of the Applicant's Equal Billing Plan for each of the years 2002 to 2005 (actual); 2006 (most recent forecast) and 2007 (budget).

RESPONSE

a) Enbridge Gas Distribution believes that the Equal Billing Plan (now called the Budget Billing Plan) should not be compared to the Risk Management Program as the Plan is not limited solely to system gas customers and does not impact the price the

Witnesses: A. Creery
D. Charleson
K. Irani
S. McGill

customer pays for their commodity. The Budget Billing Plan only impacts the timing of when they pay for their distribution and commodity costs, not the actual costs they pay. The Risk Management Program directly impacts the commodity costs paid by system gas customers.

b) There are no incremental costs related to the Budget Billing Plan.

Witnesses: A. Creery
D. Charleson
K. Irani
S. McGill

ENERGY PROBE INTERROGATORY #21

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

a) For a customer using the average volume of gas, what has been the average bill impact of risk management for the period 2002-2006?

b) For the two most recent QRAMs, please provide a detailed explanation of how the PGVA without risk management is calculated.

RESPONSE

a) Assuming a typical heating and water heating customer will consume approximately 3,062 m^3 of gas over the course of the year, if the Purchase Gas Variance Account ("PGVA") reference price is used as a proxy to determine the customer commodity cost, the average bill impact of risk management on a calendar year basis for the period 2002-2005 has been (in dollars and cents):

Year	PGVA based Commodity cost with Risk Management	PGVA based Commodity cost without Risk Management	Bill Impact of Risk Management
2002	684.82	679.55	5.27
2003	852.25	851.98	0.26
2004	898.99	898.24	0.76
2005	1,108.62	1,110.62	(2.00)
2006	1,324.37	1,319.63	4.74
Average	973.81	972.01	1.80

Witnesses: D. Charleson
K. Irani
D. Small

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b) Please find attached a copy of an explanation of the manner in which the PGVA reference price is calculated for the purposes of the QRAM and how Risk Management activities are incorporated into this calculation that was originally filed in the EB-2004-0492 proceeding at Exhibit Q2-2, Tab 1, Schedule 1. The same methodology has been used to calculate the PGVA for the two most recent QRAMs.

To determine the PGVA without Risk Management, only the steps identified in paragraphs 2 through 4 would be used. The remaining steps related to Risk Management impacts would be excluded.

Witnesses: D. Charleson
K. Irani
D. Small

QRAM METHODOLOGY AND RISK MANAGEMENT

Purpose of Evidence

1. The purpose of this evidence is to respond to the concerns expressed by the Board in its Decision in RP-2003-0203 regarding the impact of a rolling 12-month hedge period on the QRAM methodology.
2. The current QRAM methodology applies a 21-day average of future monthly indices to the Board approved gas supply portfolio in order to calculate an average annual gas acquisition cost inclusive of risk management transactions and upstream transportation costs.
3. For example, the October 1, 2004 Reference Price was based upon a 21-day average of various prices from July 16, 2004 to August 13, 2004 for the 12 months commencing October 1, 2004 and applied those monthly prices to the 2005 budgeted annual volume of gas purchases. The forecasted October 2004 AECO price was applied to the budgeted October 2004 AECO purchases, the forecasted November 2004 AECO price was applied to the budgeted November 2004 AECO purchases, ... the forecasted September 2005 AECO price was applied to the budgeted September 2005 AECO purchases, etc, etc.
4. For subsequent QRAM's the same annual Board approved volumes are used assuming a future 12-month period. For example, The January 1, 2005 Reference price was based upon a 21-day average of various prices from October 18, 2004 to November 15, 2004 for the 12 months commencing January 1, 2005. The forecasted October 2005 AECO price was applied to the budgeted October 2004 AECO purchases etc, etc.
5. As we move through the fiscal year the Company may or may not enter into risk management transactions dependent upon the outputs of the Risk Management Model. To the extent that the Company does enter into risk management

transactions they are only entered into up until the end of the current fiscal year. Using the same 21-day average of prices used in calculating the projected cost of the budgeted physical supplies the projected cash settlement of any risk management transaction can be forecasted. This forecast is included in the derivation of the Reference Price.

6. For example, under the current approach, in calculating the January 1, 2005 Reference Price any risk management transaction entered into by November 15, 2004 that covered the January 2005 to September 2005 period would be included in the derivation of that price. The forecasted January 2005 AECO price would be applied to January 2005 AECO risk management transactions, the forecasted February 2005 AECO price would be applied to February 2005 AECO risk management transactions, ... the forecasted September 2005 AECO price would be applied to September 2005 risk management transactions, etc, etc.

7. In RP-2003-0203 the Company proposed a number of changes to its Risk Management Program. Among them was the concept of a rolling 12-month hedge period. The concept was that if a Reference Price was being established for a rolling 12-month period then the Company should be allowed to enter into risk management transactions in months that matched the period of the QRAM even if it went beyond the fiscal year end date. For example, if the January 2005 Reference Price was based upon prices for 12 months commencing January 1, 2005 then the Company should be allowed to enter into risk management transactions that covered that same period.

8. Once a transaction has been entered into then the forecasted financial settlement of that transaction would be included in the derivation of the reference price. Therefore, for purposes of the QRAM, there is no change in methodology by moving to the inclusion of a rolling 12-month hedging period.

ENERGY PROBE INTERROGATORY #24

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

During the Oral Hearing in the EB2005-0001 Enbridge Gas Distribution 2006 Rates Case, on Day 5, very early on in that proceeding, Mr. Warren was cross-examining Mr. Charleson on evidence submitted in that proceeding by Mr. Adams of Energy Probe, and elicited the following response from Mr. Charleson:

> So given that there is the potential that, at periods of time, the cost -- commodity cost will be higher as a result of risk-management activities. However -- and I believe, in the proceeding last year, Mr. Smart from Risk Advisory testified that, over a longer period of time, the expectation would be that the impacts of the risk-management program should ultimately be cost-neutral, that, if you look - whether it's a five- or looking over a ten-year horizon, you're going to have some years where costs may be higher as a result of risk-management actions. There will be years where the risks are lower. But, in essence, the program should balance out. The principle of the program is not to try to beat the market. It is to mitigate and suppress volatility.
> (EB-2005-0001 Transcript Vol 5, Page 69, beginning at Line 9)

a) Is it still the position of the Applicant, as advised by Mr. Smart, that the Risk Management Program should be cost neutral, that the Program should balance out?

b) Is it still the position of the Applicant, as advised by Mr. Smart, that the Risk Management Program should not try to beat the market?

c) How does the Applicant define "beat the market"? Does that refer to an attempt to beat the wholesale commodity price?

Witnesses: D. Charleson
K. Irani

RESPONSE

a) The correct name of the Risk Advisory consultant is Mr. Simard. A correction to this error in the EB-2005-001 Transcript was missed by the Company during that proceeding. It is still the position of Enbridge Gas Distribution that over the long term, the outcome of Risk Management activities should be cost neutral.

b) Yes.

c) The Company's view is that attempting to "beat the market" would mean that a party would be consistently trying to ensure that its hedging activities resulted in a lower cost than if it had not undertaken any hedge activities. Achieving this would typically require correctly speculating on the future direction of market prices and taking the appropriate financial position.

Witnesses: D. Charleson
K. Irani

ENERGY PROBE INTERROGATORY #25

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

The evidence at D1/T4/S3, Page 11 of 14, at Paragraph 29 refers to the survey of customers that the Applicant undertook late in 2004, and quotes as follows:

> The survey found that a majority of customers want price volatility risk to be managed, thus reinforcing the Company's view that reduced price volatility is of considerable interest to customers."

a) Please advise that it is still the position of the Applicant that the survey found that customers showed little differences in opinion on the value of the risk management, whether or not they were part of the Program, and as opined by Mr. Rubino in response to Mr. O'Leary during questions-in-chief:

> The company disagrees with this assertion that the survey was biased. Both system-gas and direct-purchase customers were included in the survey. And the survey found that there were no significant differences between the responses of direct-purchase customers -- as compared to those of system-gas customers.
> (EB-2005-0001 Transcript Vol 5, Page 63, beginning at Line 28)

b) Please advise that it is still the position of the Applicant that the survey found that the customers most tolerant of bill fluctuations were as described by Mr. Rubino during questions-in-chief by Mr. O'Leary:

> The attachment at Exhibit A3, tab 3, schedule 1, page 33, indicates that, in fact, those customers who are system-gas customers, but believe they're on direct-purchase are the most tolerant of bill fluctuations.
> (EB-2005-0001 Transcript Vol 5, Page 64, beginning at Line 13)

Witnesses: D. Charleson
K. Irani

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RESPONSE

a) The survey results have not been updated or changed since the EB-2005-0001 proceeding. As a result, the position of Enbridge Gas Distribution has not changed.

b) The survey results have not been updated or changed since the EB-2005-0001 proceeding. As a result, the position of Enbridge Gas Distribution has not changed.

Witnesses: D. Charleson
K. Irani

ENERGY PROBE INTERROGATORY #16

INTERROGATORY

Ref: D1/T4/S1 & D1/T4/S2

Issue Number: 3.1
Issue: Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

a) Please confirm that the anticipated cost of hedge instruments related to transactions of the Applicant's Risk Management Program is folded into the calculation of the gas cost forecast to develop the PGVA Reference Price.

b) Please confirm that the actual cost of hedge instruments related to transactions of the Applicant's Risk Management Program is trued up each quarter in the QRAM.

c) Please advise the number of years the Applicant retains a record of the method of calculation of its annual gas cost forecast, and the calculation itself.

d) Please advise the number of years the Applicant retains a record of each transaction undertaken as part its Risk Management Program, and the cost (expense) of each of those transactions.

RESPONSE

a) Confirmed. See response to Energy Probe Interrogatory # 21 at Exhibit I, Tab 5, Schedule 21.

b) The actual cost of hedge instruments, like actual acquisition costs, are imbedded in the year projected PGVA balance that is presented as a part of the QRAM for determination on whether or not there should be a Rider.

c) The PGVA mechanism has been in place for more than 10 years. There has not been a material change to the PGVA methodology since that time. EGD has available the pertinent details of the PGVA calculation since the inception of the QRAM in January 2002.

d) EGD has maintained a record of each transaction undertaken as part of its Risk Management Program, and the cost (expense) of each of those transactions since the inception of the Risk Management program.

Witnesses: D. Charleson
D. Small

ENERGY PROBE INTERROGATORY #17

INTERROGATORY

Ref: D1/T4/S1 & D1/T4/S2

Issue Number: 3.1
Issue: Is the proposed 2007 gas cost forecast including the calculation of the PGVA Reference Price appropriate?

a) Please provide the Board with the forecast cost (expense), as reflected in the PGVA Reference Price, of the hedge instruments related to transactions of the Applicant's Risk Management Program for each year from 2002-2006, and the for the Test Year.

b) Please provide the Board with a table tabulating the cost (expense) of those hedge instruments related to transactions of the Applicant's Risk Management Program by quarter for each year from 2002-2005 (actual), 2006 (most recent forecast) and 2007 (budget), and indicating the variance between forecast and actual on an annual basis.

RESPONSE

a) A description of the QRAM methodology has been filed as part of response to Energy Probe Interrogatory # 21. Table 1 (attached) provides the PGVA Reference Price as per each QRAM effective January 1, 2002 (Col 3). It also provides the forecasted Risk Management cost at the time of the preparation of that QRAM (Col 4) and what the Reference Price would have been if Risk Management was not included (Col 6). To reiterate, any Risk Management transaction that had been entered into 45 days prior to the effective date of the QRAM would be included in the derivation of the PGVA Reference Price using the same 21 day average of prices that is applied to the forecasted volumes for rate making purposes. Any change in those prices will impact the final outcome of those Risk Management transactions just as it will impact the cost of the physical supplies being acquired. Any variation in the monthly acquisition cost including Risk Management as referenced against the PGVA Reference Price will be charged to the PGVA account.

Witnesses: D. Charleson
D. Small

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b) Table 2 attached provides the actual monthly acquisition cost (Col 1) and actual monthly risk management cost (Col 4) for the years 2002 to 2005. Column 3 of the table provides the average monthly acquisition cost unit rate excluding the impact of risk management activity and Column 6 represents the monthly acquisition cost unit rate including Risk Management. For comparative purposes the risk management costs as a percentage of the annual acquisition cost has been provided.

Witnesses: D. Charleson
D. Small

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Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (Col.2 - Col.4)	Col. 6	Col. 7 (Col.3 - Col.6)	Col. 8 (Col.4 / Col. 5)
	QRAM Forecast Volumes 10*3 m*3	QRAM Forecast Costs $(000)	PGVA Reference Price $/10*3 m*3	Forecasted Risk Management $(000)	QRAM Costs without Risk Management $(000)	PGVA without Risk Management $/10*3 m*3	Risk Management Impact $/10*3 m*3	%
January 1, 2002 QRAM	4,859,665.5	1,071,371.2	220.462	10,890.4	1,060,480.8	218.221	2.241	1.03
April 1, 2002 QRAM	4,686,351.0	906,915.3	193.523	22,212.6	884,702.7	188.783	4.740	2.51
July 1, 2002 QRAM	4,686,351.0	1,185,062.1	252.875	(6,247.5)	1,191,309.6	254.208	(1.333)	(0.52)
October 1, 2002 QRAM	3,728,052.4	887,139.1	237.963	-	887,139.1	237.963	-	-
January 1, 2003 QRAM	4,165,740.4	1,081,089.8	259.519	1,682.7	1,079,407.0	259.115	0.404	0.16
April 1, 2003 QRAM	4,165,740.4	1,303,365.0	312.877	(2,339.5)	1,305,704.6	313.439	(0.562)	(0.18)
July 1, 2003 QRAM	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
October 1, 2003 QRAM	4,142,394.0	1,160,621.7	280.181	442.2	1,160,179.6	280.075	0.107	0.04
January 1, 2004 QRAM	4,142,394.0	1,090,264.1	263.197	3,562.0	1,086,702.1	262.337	0.860	0.33
April 1, 2004 QRAM	4,142,394.0	1,213,267.9	292.891	(1,177.5)	1,214,445.4	293.175	(0.284)	(0.10)
July 1, 2004 QRAM	4,142,394.0	1,379,047.5	332.911	(5,937.7)	1,384,985.2	334.344	(1.433)	(0.43)
October 1, 2004 QRAM	5,032,476.1	1,671,970.6	332.236	-	1,671,970.6	332.236	-	-
January 1, 2005 QRAM	5,032,476.1	1,793,207.8	356.327	(12,364.0)	1,805,571.9	358.784	(2.457)	(0.68)
April 1, 2005 QRAM	5,032,476.1	1,606,796.6	319.285	5,465.4	1,601,331.2	318.199	1.086	0.34
July 1, 2005 QRAM	5,032,476.1	1,790,075.4	355.705	(399.8)	1,790,475.2	355.784	(0.079)	(0.02)
October 1, 2005 QRAM	5,032,476.1	1,995,712.2	396.567	5,549.9	1,990,162.3	395.464	1.103	0.28
January 1, 2006 QRAM	4,995,136.3	2,418,617.8	484.195	(3,887.1)	2,422,504.9	484.973	(0.778)	(0.16)
April 1, 2006 QRAM	4,995,136.3	1,995,964.2	399.582	15,556.1	1,980,408.1	396.467	3.114	0.79
July 1, 2006 QRAM	4,995,136.3	1,906,602.8	381.692	18,960.7	1,887,642.0	377.896	3.796	1.00
October 1, 2006 QRAM	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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Table 2

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
			(Col.1/Col.2)		(Col.1+Col.4)	(Col.5/Col.2)		(Col.6+Col.7)	(Col.8/Col.
	Gas Acquisition Costs $(000)	Acquired Volumes 10*3 m*3	$/10*3 m*3	Risk Management Impact $(000)	Risk Management Adjusted Cost $(000)	$/10*3 m*3	PGVA Adjustment $(000)	Deemed Acquisition Cost $(000)	PGVA Reference Price $/10*3 m*3
2002									
January	43,775.3	226,272.4	193.463	4,317.1	48,092.4	212.542	1,792.1	49,884.5	220.462
February	41,008.3	224,344.8	182.792	7,084.0	48,092.3	214.368	1,367.2	49,459.5	220.462
March	35,614.8	181,656.7	196.055	6,403.8	42,018.6	231.308	(1,970.2)	40,048.4	220.462
April	49,973.2	219,824.3	227.332	(546.8)	49,426.4	224.845	(6,885.3)	42,541.1	193.523
May	65,329.4	298,789.4	218.647	(982.7)	64,346.7	215.358	(6,524.1)	57,822.6	193.523
June	59,525.0	282,277.8	210.874	549.0	60,074.0	212.819	(5,446.8)	54,627.2	193.523
July	71,760.2	389,179.9	184.388	4,181.9	75,942.1	195.134	22,471.8	98,413.9	252.875
August	63,912.0	387,779.7	164.815	7,598.5	71,510.5	184.410	26,549.3	98,059.8	252.875
September	59,456.7	305,984.6	194.313	2,994.2	62,450.9	204.098	14,925.0	77,375.9	252.875
October	76,029.9	328,074.2	231.746	-	76,029.9	231.746	2,039.7	78,069.5	237.963
November	105,629.3	399,493.4	264.408	505.7	106,135.0	265.674	(11,070.3)	95,064.6	237.963
December	105,349.0	402,019.3	262.050	947.9	106,296.9	264.408	(10,631.2)	95,665.7	237.963
	777,363.0	3,645,696.4	213.228	33,052.6	810,415.6	222.294	26,617.0	837,032.7	229.595
Risk Management as a percentage of Acquisition Costs				4.25					
2003									
January	198,269.1	643,092.4	308.306	(1,661.3)	196,607.9	305.723	(29,713.2)	166,894.7	259.519
February	272,975.4	631,009.4	432.601	(4,923.3)	268,052.0	424.799	(104,293.1)	163,758.9	259.519
March	276,281.7	580,985.7	475.540	(21,944.6)	254,337.1	437.768	(103,560.3)	150,776.8	259.519
April	118,004.9	379,500.2	310.948	(485.5)	117,519.4	309.669	1,217.5	118,736.9	312.877
May	102,047.3	338,141.3	301.789	268.3	102,315.6	302.582	3,481.1	105,796.6	312.877
June	100,697.2	318,903.2	315.761	(173.2)	100,524.1	315.218	(746.6)	99,777.5	312.877
July	107,161.8	359,162.5	298.366	42.3	107,204.1	298.484	5,169.6	112,373.7	312.877
August	84,166.7	329,780.9	255.220	2,665.4	86,832.1	263.302	16,348.8	103,180.9	312.877
September	94,639.1	339,520.9	278.743	1,385.2	96,024.3	282.823	10,204.0	106,228.3	312.877
October	86,774.2	335,055.7	258.984	381.5	87,155.7	260.123	6,720.5	93,876.2	280.181
November	97,008.0	384,282.4	252.439	2,284.2	99,292.2	258.383	8,376.4	107,668.6	280.181
December	137,281.2	498,129.2	275.594	2,632.3	139,913.5	280.878	(347.1)	139,566.3	280.181
	1,675,306.7	5,137,563.8	326.090	(19,528.8)	1,655,777.9	322.289	(187,142.4)	1,468,635.5	285.862
Risk Management as a percentage of Acquisition Costs				(1.17)					
2004									
January	172,077.0	506,607.4	339.665	(3,210.3)	168,866.7	333.328	(35,529.1)	133,337.5	263.197
February	126,796.7	418,968.9	302.640	(566.1)	126,230.6	301.289	(15,959.2)	110,271.4	263.197
March	97,680.0	349,455.9	279.520	5,151.9	102,831.9	294.263	(10,856.1)	91,975.7	263.197
April	99,503.7	343,798.7	289.424	184.9	99,688.6	289.962	1,007.0	100,695.6	292.891
May	105,514.6	342,182.5	308.358	(690.0)	104,824.6	306.341	(4,602.5)	100,222.2	292.891
June	109,995.3	331,057.1	332.255	(3,228.1)	106,767.2	322.504	(9,803.5)	96,963.6	292.891
July	145,749.3	476,835.3	305.660	(1,570.1)	144,179.2	302.367	14,564.5	158,743.7	332.911
August	138,917.1	478,215.7	290.491	(285.8)	138,631.3	289.893	20,572.0	159,203.3	332.911
September	101,671.6	400,378.3	253.939	3,377.8	105,049.4	262.375	28,241.0	133,290.3	332.911
October	70,498.6	254,521.0	276.985	-	70,498.6	276.985	14,062.4	84,561.0	332.236
November	129,304.6	357,839.7	361.348	31.4	129,336.0	361.436	(10,448.8)	118,887.2	332.236
December	161,565.8	474,518.2	340.484	4,759.8	166,325.7	350.515	(8,673.6)	157,652.0	332.236
	1,459,274.3	4,734,378.8	308.229	3,955.4	1,463,229.7	309.065	(17,426.0)	1,445,803.7	305.384
Risk Management as a percentage of Acquisition Costs				0.27					
2005									
January	160,784.8	508,205.4	316.378	9,730.3	170,515.2	335.524	10,572.1	181,087.3	356.327
February	119,940.3	405,114.9	296.065	9,340.5	129,280.8	319.121	15,072.6	144,353.4	356.327
March	184,831.0	598,717.2	308.712	10,676.8	195,507.8	326.544	17,831.3	213,339.1	356.327
April	124,672.3	364,889.5	341.671	(1,048.7)	123,623.5	338.797	(7,119.8)	116,503.8	319.285
May	113,460.8	353,833.7	320.661	(533.8)	112,927.0	319.153	46.9	112,973.8	319.285
June	102,940.1	340,033.6	302.735	2,623.6	105,563.7	310.451	3,004.0	108,567.6	319.285
July	113,580.2	343,057.4	331.082	(201.6)	113,378.7	330.495	8,648.6	122,027.2	355.705
August	148,517.0	428,990.8	346.201	(1,111.8)	147,405.2	343.609	5,189.0	152,594.2	355.705
September	188,904.3	425,592.3	443.862	(16,908.3)	171,996.0	404.133	(20,610.7)	151,385.3	355.705
October	162,465.1	303,136.6	535.947	-	162,465.1	535.947	(42,251.3)	120,213.9	396.567
November	173,655.6	353,462.3	491.299	(3,013.1)	170,642.5	482.774	(30,471.1)	140,171.4	396.567
December	333,556.0	665,069.8	501.535	7,924.7	341,480.7	513.451	(77,736.2)	263,744.5	396.567
	1,927,307.4	5,090,103.7	378.638	17,478.7	1,944,786.1	382.072	(117,824.6)	1,826,961.5	358.924
Risk Management as a percentage of Acquisition Costs				0.91					

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ENERGY PROBE INTERROGATORY #18

INTERROGATORY

Ref: D1/T4/S3

Issue Number: 3.10
Issue: Is the continuation of the Risk Management Program appropriate in the context of the Board's 2006 Decision directives?

The Evidence at D1/T4/S3, Page 6 of 14 at Paragraph 17 states:

> To assess the effect of the Program on reducing overall price volatility in the QRAM, the Company analyzed the impact of the Program on the PGVA for the period January 1, 2002 up to and including April 1, 2006. The Company believes this is the most appropriate means of assessing the effectiveness of the Program, as the PGVA reference price is a key determinant in the setting of the QRAM price.

And again at Paragraph 18, the Evidence continues as follows:

> Table 2 compares the absolute change in the PGVA reference price for each quarter, with or without the Program.

a) Please complete Table A below to demonstrate the Equal Billing Plan impact on price volatility of the hedged portfolio.

b) Please complete Table B below to demonstrate the Equal Billing Plan impact on price volatility of the unhedged portfolio used in Table 2 of the Evidence on Page 7 of 14.

Witnesses: D. Charleson
K. Irani

44

Table A – EQUAL BILLING PLAN IMPACT ON PRICE VOLATILITY
2002-2006
Hedged Portfolio

	Residential Consumer Per 273 m3 Monthly With RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 With RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02					
1-Apr-02					
1-Jul-02					
1-Oct-02					
1-Jan-03					
1-Apr-03					
1-Jul-03					
1-Oct-03					
1-Jan-04					
1-Apr-04					
1-Jul-04					
1-Oct-04					
1-Jan-05					
1-Apr-05					
1-Jul-05					
1-Oct-05					
1-Jan-06					
1-Apr-06					
1-Jul-06					

Witnesses: D. Charleson
K. Irani

Table B – EQUAL BILLING PLAN IMPACT ON PRICE VOLATILITY
2002-2006
Unhedged Portfolio

	Residential Consumer Per 273 m3 Monthly No RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 No RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02					
1-Apr-02					
1-Jul-02					
1-Oct-02					
1-Jan-03					
1-Apr-03					
1-Jul-03					
1-Oct-03					
1-Jan-04					
1-Apr-04					
1-Jul-04					
1-Oct-04					
1-Jan-05					
1-Apr-05					
1-Jul-05					
1-Oct-05					
1-Jan-06					
1-Apr-06					
1-Jul-06					

RESPONSE

The unit cost of gas that a customer pays in their bill is not impacted in any way by the Equal Billing Plan (now called the Budget Billing Plan). This plan is intended to spread higher monthly payments for commodity and distribution services over the course of the year. The price that a customer ultimately pays, whether driven by the system gas rate or the direct purchase arrangements of the customer, is not impacted in any way by the

Witnesses: D. Charleson
K. Irani

Budget Billing Plan. The Budget Billing Plan strictly changes the timing of when the price is paid. The requested tables are provided below with the "Equal Billing Price" being the commodity price for a system gas customer.

Table A - EQUAL BILLING PLAN IMPACT OF PRICE VOLATILITY
2002-2006
Hedged Portfolio

	Residential Consumer Per 273 m3 Monthly With RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 With RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02	60.19		60.19		
1-Apr-02	52.83	(7.35)	52.83	(7.35)	-
1-Jul-02	69.03	16.20	69.03	16.20	-
1-Oct-02	64.96	(4.07)	64.96	(4.07)	-
1-Jan-03	70.85	5.88	70.85	5.88	-
1-Apr-03	85.42	14.57	85.42	14.57	-
1-Jul-03	85.42	-	85.42	-	-
1-Oct-03	76.49	(8.93)	76.49	(8.93)	-
1-Jan-04	71.85	(4.64)	71.85	(4.64)	-
1-Apr-04	79.96	8.11	79.96	8.11	-
1-Jul-04	90.88	10.93	90.88	10.93	-
1-Oct-04	90.70	(0.18)	90.70	(0.18)	-
1-Jan-05	97.28	6.58	97.28	6.58	-
1-Apr-05	87.16	(10.11)	87.16	(10.11)	-
1-Jul-05	97.11	9.94	97.11	9.94	-
1-Oct-05	108.26	11.16	108.26	11.16	-
1-Jan-06	132.19	23.92	132.19	23.92	-
1-Apr-06	109.09	(23.10)	109.09	(23.10)	-
1-Jul-06	104.20	(4.88)	104.20	(4.88)	-

Witnesses: D. Charleson
K. Irani

Table B - EQUAL BILLING PLAN IMPACT OF PRICE VOLATILITY
2002-2006
Unhedged Portfolio

	Residential Consumer Per 273 m3 Monthly With RM	Quarterly Price Change Per 273 m3	Equal Billing Price Per 273 m3 With RM	Quarterly Price Change Per 273 m3	Percentage Reduction in Volatility (%)
Date					
1-Jan-02	59.57		59.57		
1-Apr-02	51.54	(8.04)	51.54	(8.04)	-
1-Jul-02	69.40	17.86	69.40	17.86	-
1-Oct-02	64.96	(4.43)	64.96	(4.43)	-
1-Jan-03	70.74	5.77	70.74	5.77	-
1-Apr-03	85.57	14.83	85.57	14.83	-
1-Jul-03	85.57	-	85.57	-	-
1-Oct-03	76.46	(9.11)	76.46	(9.11)	-
1-Jan-04	71.62	(4.84)	71.62	(4.84)	-
1-Apr-04	80.04	8.42	80.04	8.42	-
1-Jul-04	91.28	11.24	91.28	11.24	-
1-Oct-04	90.70	(0.58)	90.70	(0.58)	-
1-Jan-05	97.95	7.25	97.95	7.25	-
1-Apr-05	86.87	(11.08)	86.87	(11.08)	-
1-Jul-05	97.13	10.26	97.13	10.26	-
1-Oct-05	107.96	10.83	107.96	10.83	-
1-Jan-06	132.40	24.44	132.40	24.44	-
1-Apr-06	108.24	(24.16)	108.24	(24.16)	-
1-Jul-06	103.17	(5.07)	103.17	(5.07)	-

Witnesses: D. Charleson
K. Irani

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
Attachment

Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

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Study Background

Overview of Objectives

- Ipsos-Reid was commissioned by Enbridge Gas Distribution ("EGD") to conduct quantitative survey research for residential (rate 1) and small commercial[1] (rate 6) customers to understand their sensitivity to price volatility and related issues. The specific objectives of the research were to:
  - Assess customers' level of knowledge, understanding and expectations about gas pricing and EGD's role in the process
  - Determine customers' expectations about gas prices and their sensitivity to price volatility
  - Understand customers' preferences for risk management strategies in general and under different market conditions
  - Determine customers' preferences for the frequency of administering bill adjustments

[1] "Small Commercial" includes commercial, industrial, institutional and multi-residential customers with an annual natural gas consumption of <= 75,000 m^3.

Methodology

- A total of 1200 telephone interviews (computer assisted telephone interviewing) were conducted among 800 residential (rate 1) customers and 400 small commercial (rate 6) customers.
  - With a sample size of 800, results are considered accurate to within +/- 3.5%, at a 95% confidence level.
  - With a sample size of 400, results are considered accurate to within +/- 4.9%, at a 95% confidence level.
- Interviews were conducted between November 22nd and December 7th, 2004.
- Respondents were screened to ensure the interview was conducted with the person in the household or business that was responsible for making decisions regarding energy-related products and services and paying the monthly natural gas bill.
- Based on Enbridge Gas Distribution's records,
  - Of the 800 residential customers interviewed, 382 were system gas customers and 418 were direct purchase customers,
  - Of the 400 commercial customer interviewed, 193 were system gas customers and 207 were direct purchase small commercial customers.

Methodology Cont'd…

- The reporting of the results focuses on:
  - All customers (combined residential and small commercial responses)
  - Residential versus small commercial
- Some results are also presented based on customers' awareness of their natural gas commodity supplier:
  - System Gas ("SG") Actual: System Gas customers who are aware that they purchase their natural gas commodity from Enbridge
  - Direct Purchase ("DP") Actual: Direct Purchase customers who are aware that they purchase their natural gas commodity from a broker
  - Direct Purchase ("DP") – System Gas Perceived: Direct Purchase customers who believe they purchase their natural gas commodity from Enbridge
  - System Gas – Direct Purchase ("DP") Perceived: System Gas customers who believe they purchase their natural gas commodity from a broker

Note: The sums of the individual response categories may not add to 100% due the effect of rounding.

Ipsos Reid

Executive Summary

Executive Summary

Understanding and Perceptions of Natural Gas Pricing

- While the majority of system gas customers are aware that they purchase their natural gas commodity from Enbridge Gas Distribution (90%), nearly three-in-five direct purchase customers (58%) continue to believe they purchase their natural gas commodity from Enbridge.
- Three-quarters of customers (75%) expect the market price for the natural gas commodity will increase over the next year.
- Sixteen percent of all customers (13% of residential and 22% of small commercial customers) believe that utilities like Enbridge have the most responsibility when dealing with issues related to natural gas pricing.
- More than four-in-five of all customers (83%) believe that Enbridge makes a profit from the price charged for the supply of the natural gas commodity.
- More than one-third of all customers (35%) think that the market price that Enbridge pays for the natural gas commodity it buys remains stable over the year.
- According to just over one-half of all respondents (54%), Enbridge should purchase the natural gas commodity at a fixed price instead of a floating rate.
  - Direct Purchase customers (56%) are somewhat more likely than System Gas customers (47%) to say that the company should purchase natural gas at a fixed rate.

Executive Summary Cont'd…

Sensitivity to Price Volatility

- 57% of all customers think it is more important to maintain a steady price than to obtain the lowest price.
  - Somewhat more small commercial than residential customers believe it is more important to maintain a steady price than to obtain the lowest price (62% vs. 55%).
  - Direct purchase customers are more likely than system gas customers to find a steady price to be most important (63% DP Actual versus 51% SG Actual).
- Customer expectations about the future of natural gas prices seem to affect their sensitivity to price volatility. Customers that expect the market price for natural gas to increase over the next year are more likely to:
  - prefer that Enbridge purchase natural gas at a fixed rate (56% versus 41% for customers who expect a price decrease)
  - believe that maintaining a steady price is more important than obtaining the lowest price (58% versus 35% for customers who expect a price decrease).
- Only one-half (50%) of customers report noticing a bill adjustment made to their bill in the past year.
  - More small commercial than residential customers have noticed the adjustments (54% versus 48%).

Executive Summary Cont'd…

Sensitivity to Price Volatility Cont'd

- For all customers, as the amount of the bill adjustment increases, there is a reduced willingness to accept price fluctuations.
  - However, even at the highest level tested ($100), nearly one-half of customers (48%) reported they would be very or somewhat willing to have the commodity portion of their bill fluctuate by this amount in any one year (period of time).
    - Small commercial customers are somewhat more willing to accept a fluctuation of $100 than are residential customers (52% versus 46% very/somewhat willing).
  - At the $75 level, almost three-in-five of all customers are willing to have the commodity portion of their bill fluctuate by this amount (56% very/somewhat willing).
  - At the lowest levels tested, the majority of all customers are willing to accept the fluctuation on their bill (78% very/somewhat willing at $25; 68% very/somewhat willing at $50).
  - There is little variation in customers' willingness to accept bill fluctuations at the levels tested among type of customer (DP or SG) or supplier awareness..

Executive Summary Cont'd…

Adjustment Frequency Preferences

- In general, about six-in-ten of all customers (58%) would prefer that Enbridge make smaller, more frequent adjustments to their bill, and four-in-ten of all customers (40%) would prefer a one-time, year-end adjustment.
  - More small commercial than residential customers prefer smaller, more frequent adjustments (63% versus 55%).
- While the proportion of all customers who prefer frequent adjustments increases as the amount of the debit/credit increases, more of all customers prefer frequent adjustments under the refund scenario than the payment scenario at all adjustment levels.
  - Under the payment scenario, small commercial customers are significantly more likely to prefer a one-time adjustment than residential customers at each level tested.

Risk Management Strategy Preferences

- When no price point is attached to the question, the risk management strategy preferences of all customers rank as follows:
  - creating a high and low limit around the current price (33%)
  - purchase insurance (26%),
  - fixing prices at current levels (25%).
  - do not manage the price risk in any way (15%)

Executive Summary Cont'd…

Affect of Price Decrease on Strategy Preference

- When presented with a scenario of a 50% price decrease, nearly two-thirds of all respondents (64%) who originally stated a preference for Enbridge to fix prices at current levels indicated the scenario would change their response.
- Almost one-half (45%) of these chose a new strategy that allowed them some benefit from falling prices (7% of all respondents; 29% of those who originally selected the strategy).
- Seven percent of those who originally chose an approach that afforded some protection from increasing prices now opted for Enbridge to NOT manage the price risk in any way.

Affect of Price Decrease on Strategy Preference

- When presented with a scenario of a 50% price *increase*, less than one-third (32%) of all customers who initially preferred that Enbridge not manage the price risk indicated the scenario would change their response.
- Six-in-ten (60%) of these chose a new approach that afforded some protection from increasing prices (3% of all respondents; 19% of those who originally selected the strategy).

Recommendations

- Any issue related to "price" represents a very special challenge to Enbridge:
  - Residential and small business consumers think that the price they pay for the commodity will continue to rise
  - Consumers ultimately associate pricing issues with the utility and government
  - And consumers are generally confused on related issues such as who is profiting, what the regulatory environment is, etc.
- In this environment opinion is more divided than polarized one way or the other on options/ideas for preferences and actions on price-related issues:,
  - Fixed and steady tend to win out over floating and lowest in defining consumer preferences, although opinion is divided
  - One-time wins out over more frequent in terms of general adjustment frequency preferences when the potential refund or payment are at lower levels, while more frequent wins out over one-time as the payment/refund levels increase (especially in the case of a payment)
  - The vast majority of consumers want Enbridge to execute some kind of strategy to help manage the potential risk for large fluctuations in commodity prices; however preference is split between fixing prices at current levels, purchasing insurance or creating a high/low price band around the current price

Recommendations Cont'd…

- This suggests that there is a consumer environment:
  - With potential for skepticism about any changes that Enbridge might introduce on "pricing issues"
  - Regardless of any changes made, there is a sizeable proportion of consumers who will be more receptive and a sizeable proportion of consumers who will be less receptive to any change
    - With this in mind, if the basic principle used by Enbridge in making some of its strategic decisions is that "the majority rules," then the study results suggest that:
      - $75 represents the cut-off in terms of acceptable fluctuation in the commodity portion of consumers' bills among residential customers, and
      - $100 is the level among commercial customers.

Prices and Regulation

Natural Gas Supplier Awareness

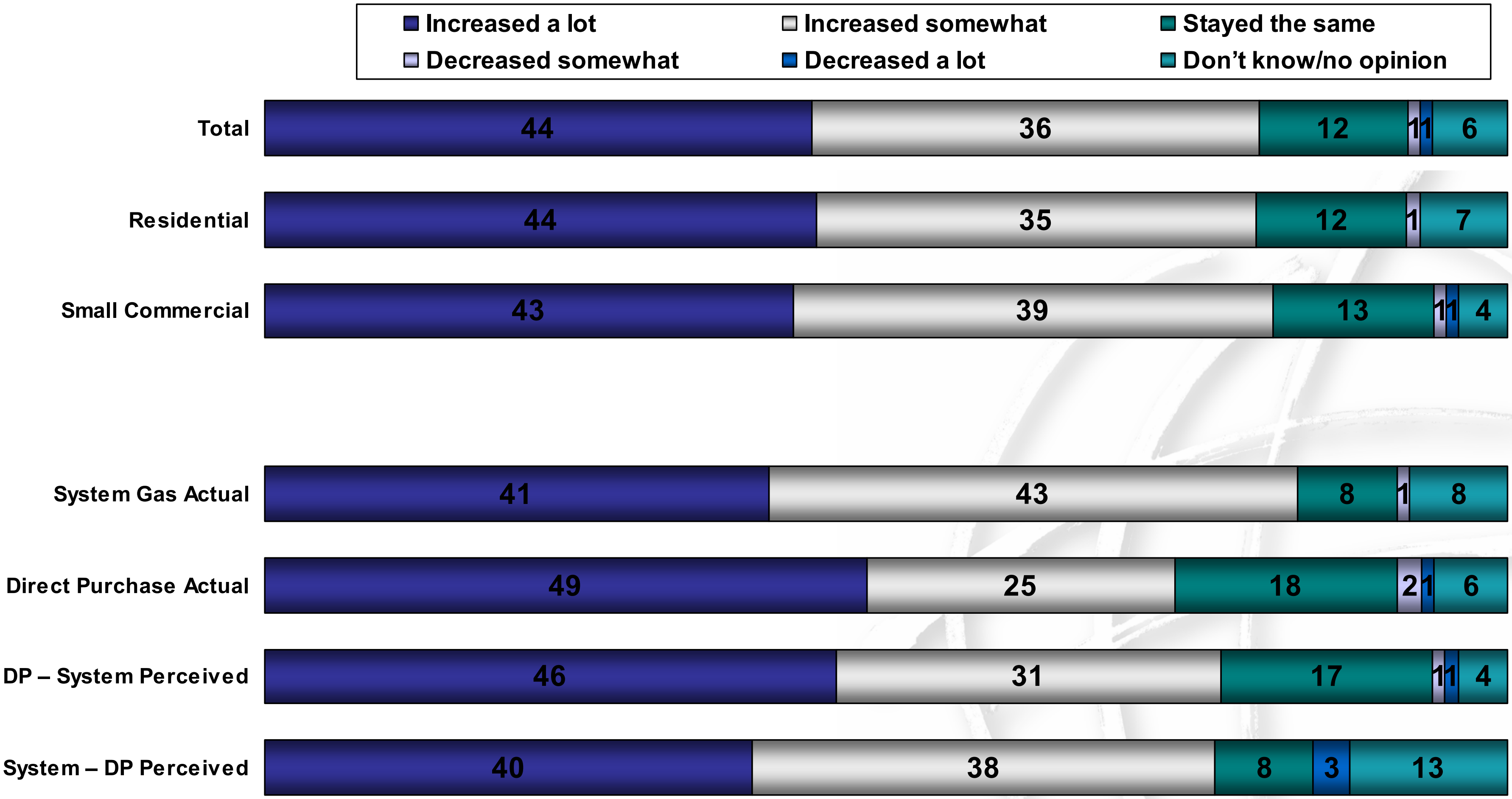
- Nearly six-in-ten (58%) direct purchase customers continue to believe that they purchase their natural gas commodity from Enbridge Gas Distribution. Less than a third (32%) are aware that they are direct purchase customers.
- Comparatively, the majority (90%) of system gas customers identified Enbridge as their supplier.
- Residential and Small Commercial customers are equally as likely to be able to identify if they are system or direct purchase gas customers.

	System Gas Customers	Direct Purchase Customers
N=	574	625
Enbridge (System Gas)	*90*	*58*
Direct Purchase Net	*7*	*32*
Direct Energy	5	23
Ontario Energy Savings Corporation	1	5
Gas Marketer (unknown)	1	3
Superior	-	1
Other	1	3
Don't know	2	7

Q1. Who do you purchase your natural gas commodity from?

Perceptions of the Market Price of Natural Gas

Four-in-five customers believe that the market price for the natural gas commodity has increased over the past two years (80% increased a lot/somewhat) and one-in-ten believe it has stayed the same (12%). These results are consistent for both residential and small commercial customers. However, System Gas customers (84%) are somewhat more likely to believe the price has increased than are Direct Purchase customers (74%).

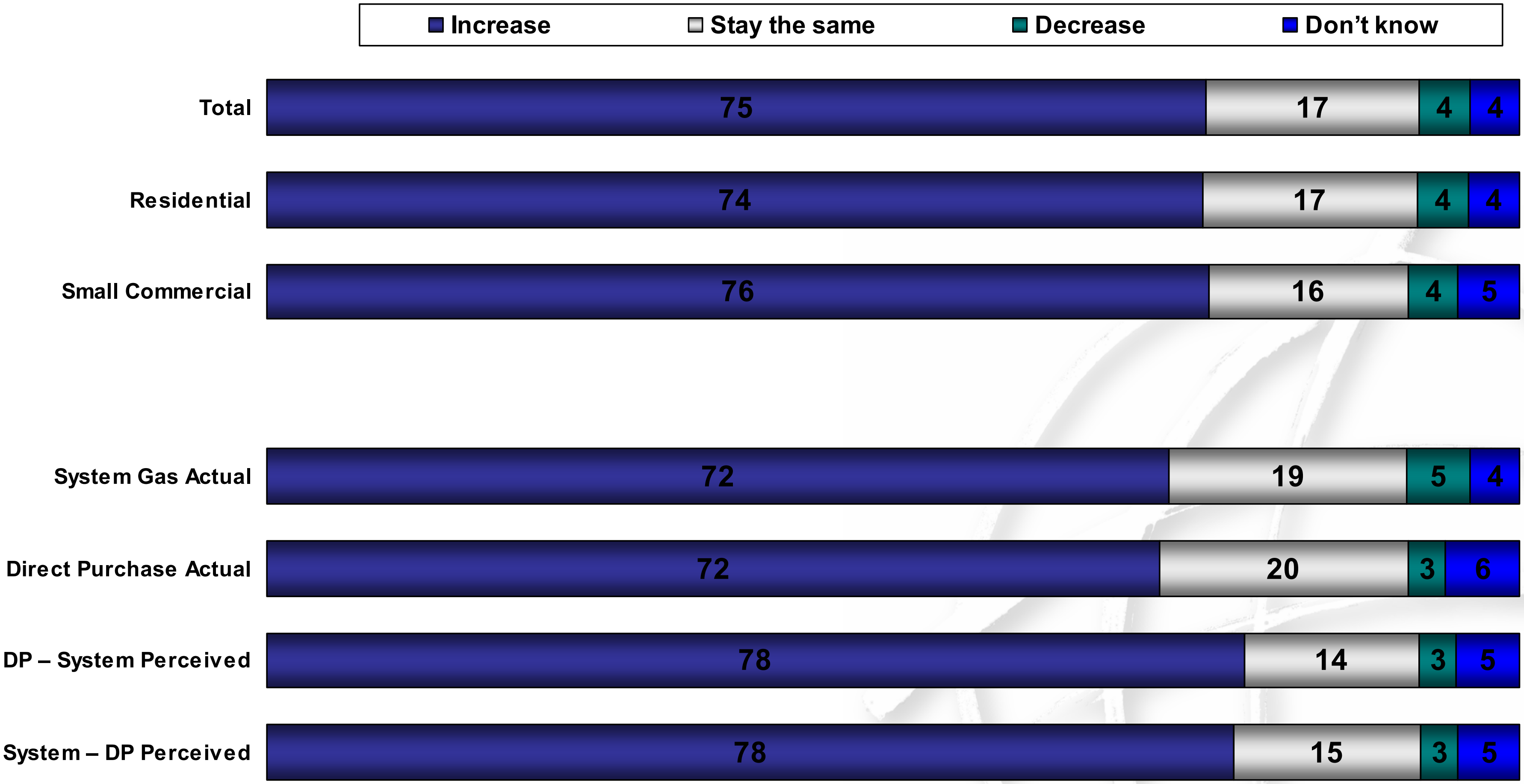


Q2. Thinking specifically about the market price for the natural gas commodity, over the past two years, would you say the price has increased a lot, increased somewhat, stayed the same, decreased somewhat, or decreased a lot?

Ipsos Reid

Perceptions of the Future of Natural Gas Prices

In addition, three-quarters of customers (75%) expect the market price for the natural gas commodity will increase over the next year and another one-in-five (17%) think it will stay the same.



Q3. And, over the next year, do you think the market price for the natural gas commodity will increase, decrease or stay the same?

Natural Gas Market Price Influencers

According to customers, the greatest impacts influencing the price for natural gas commodity are: world energy prices (18%), supply and demand (18%), availability (11%) and world events (10%).

	Total	Residential	Small Commercial
N=	1200	800	400
World energy prices	18	19	18
Supply and demand	18	17	19
Availability (supply) of natural gas	11	12	10
World events	10	8	12
High profits (greed, etc.)	7	8	6
Production/ distribution/ labour cost	7	6	8
More government control/ intervention/ regulation	6	7	5
Economy	4	3	5
Variations in climate	4	3	4
Don't know	19	18	21

Q4. What do you think would have the greatest impact on influencing the price that you pay for the natural gas commodity, that is the supply of natural gas that you use?

Responsibility for Natural Gas Price Issues

- Enbridge customers think that officials from the federal (22%) and provincial (20%) government have the most responsibility for dealing with issues associated with natural gas prices, followed by utilities (16%).
- Proportionately more small commercial customers than residential believe that utilities have the most responsibility when dealing with these issues (22% versus 13%).

	Total	Residential	Small Commercial
N=	1200	800	400
Officials from the federal government	22	22	24
Officials from the provincial government	20	22	17
Utilities like Enbridge Gas Distribution	16	13	22
Natural Gas marketers	7	8	5
Ontario Energy Board	5	5	4
Government / politicians (unspecified)	3	3	3
Customers/me/myself	3	3	2
Don't know	15	15	15

Q7. Who do you think has the most responsibility for dealing with issues associated with natural gas prices?

Regulatory Process for Distribution Rates

- Nearly six-in-ten customers (58%) agree that the Ontario government's regulatory process for setting approving distribution rates ensures fair and reasonable prices for natural gas.
- Residential customers are less likely to agree with this than are small commercial customers (56% versus 63%).

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Top 2 Box %	*58*	56	63	*58*	*53*	*58*	*78*
Strongly agree	10	10	11	10	11	10	13
Somewhat agree	48	45	53	48	42	48	65
Somewhat disagree	17	17	18	17	18	18	13
Strongly disagree	19	20	16	19	22	19	10
Don't know	6	7	3	6	8	5	-

Q8. Do you agree or disagree that the Ontario government's regulatory process for setting and approving distribution rates ensures fair and reasonable prices for natural gas?

Understanding of Natural Gas Pricing

• More than four-in-five customers (83%) believe that Enbridge makes a profit from the price charged for the supply of the natural gas commodity.
• Only about three-in-five (59%) think that the prices that Enbridge charges for delivering natural gas are regulated.

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Does Enbridge make a profit from supply?							
Yes	83	82	86	83	81	87	73
No	11	11	10	12	11	8	23
Don't know	6	6	5	5	8	5	5
Are natural gas delivery prices regulated?							
Yes	59	59	59	57	57	63	55
No	21	18	27	20	21	22	30
Don't know	20	23	14	22	22	16	15

Q5. And, as far as you know, does Enbridge make a profit from the price they charge for the supply of the natural gas commodity, that is the actual gas you use?
Q6. Are the prices that Enbridge charges for delivering natural gas to your home regulated?

Understanding of Natural Gas Pricing Cont'd…

• More than one-half of both residential and small commercial customers think that the market price that Enbridge pays for the natural gas commodity it buys changes frequently over the year (57% and 53% respectively).
• System Gas customers are somewhat more likely to think that the price changes as compared to Direct Purchase customers (59% versus 55%).

	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	1200	800	400	518	199	363	40
Does the price Enbridge pays for natural gas change?							
Changes	56	57	53	59	55	49	73
Stable	35	32	41	32	35	41	28
Don't know	9	11	7	9	11	10	-
How frequently does Enbridge set rates customers pay for natural gas?							
Every month	17	19	15	18	16	18	18
Every 3-4 months	31	31	32	33	26	30	33
Twice a year	22	21	25	25	24	18	20
Once a year	20	19	21	17	20	23	23
Don't know	10	11	8	7	15	12	8

Q9. Do you think the market price that Enbridge Gas Distribution pays to the companies from which it buys the natural gas commodity changes frequently over the year, or do they pay a stable price over the year?
Q10. Based on what you know or think is the case, how frequently does Enbridge review and set the rates that customers pay for the natural gas commodity on the bill

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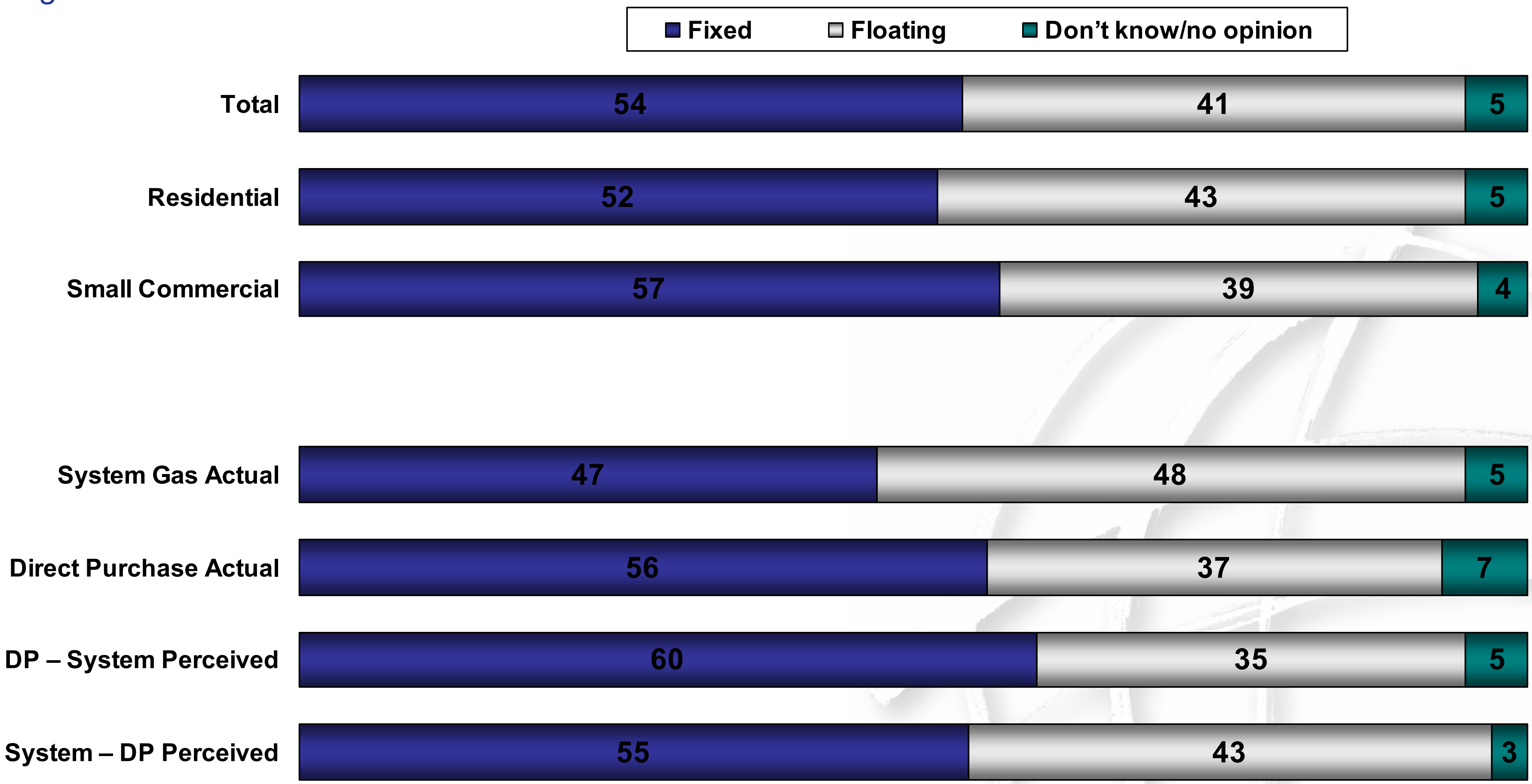
Sensitivity to Price Volatility

Fixed Price Versus Floating Rate

When asked whether Enbridge should purchase the natural gas commodity at a fixed price or at a floating rate, just over one-half of respondents (54%) said a fixed rate. Direct Purchase customers (56%) are somewhat more likely than System Gas customers (47%) to say that the company should purchase natural gas at a fixed rate.



Q11. Do you think the company should purchase the natural gas commodity at a fixed price with stable pricing but not necessarily the lowest price or do you think they should purchase the natural gas commodity at a floating rate which can lead to a lower price but also runs the risk of having to pay higher prices?

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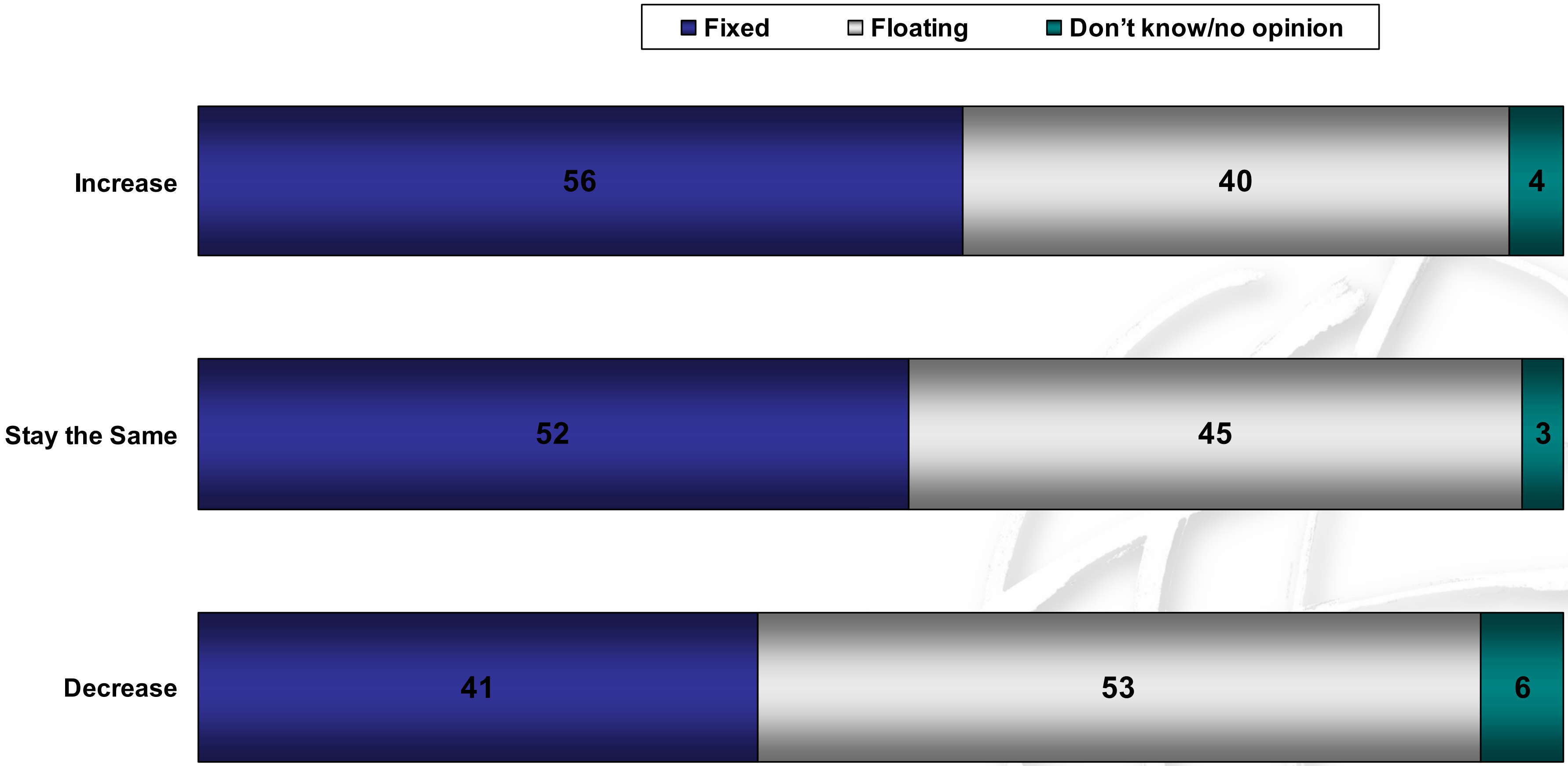
Fixed Price Versus Floating Rate And Perceptions of the Future of Natural Gas Prices

Customers that indicated they expect the market price for the natural gas commodity to increase over the next year are more likely to prefer that Enbridge purchase natural gas at a fixed rate than are customers who expect the price to decrease.



Q11. Do you think the company should purchase the natural gas commodity at a fixed price with stable pricing but not necessarily the lowest price or do you think they should purchase the natural gas commodity at a floating rate which can lead to a lower price but also runs the risk of having to pay higher prices?

Reasons for a Fixed Rate

More small commercial than residential customers state that the main reason for wanting Enbridge to purchase natural gas at a fixed rate is for stable prices with no fluctuations (57% small commercial customers and 47% residential) and for the ability to budget (24% versus 14%).

Base: Respondents who said fixed rate at Q11	Total	Residential	Small Commercial
N=	644	417	227
Stability of pricing/ no fluctuations/ no changes in prices	50	47	57
Customers know what they are paying	24	23	25
Ability to budget	18	14	24
Protects you from increasing prices	9	10	7
Able to take advantage of lower prices/ benefit from lower prices/ best price advantage	8	8	8
Consistency in our bill	6	7	4
More fair	4	3	5
Don't know	3	3	2

Q12. And, why do you think they should purchase the natural gas commodity at a fixed rate?

Reasons for a Floating Rate

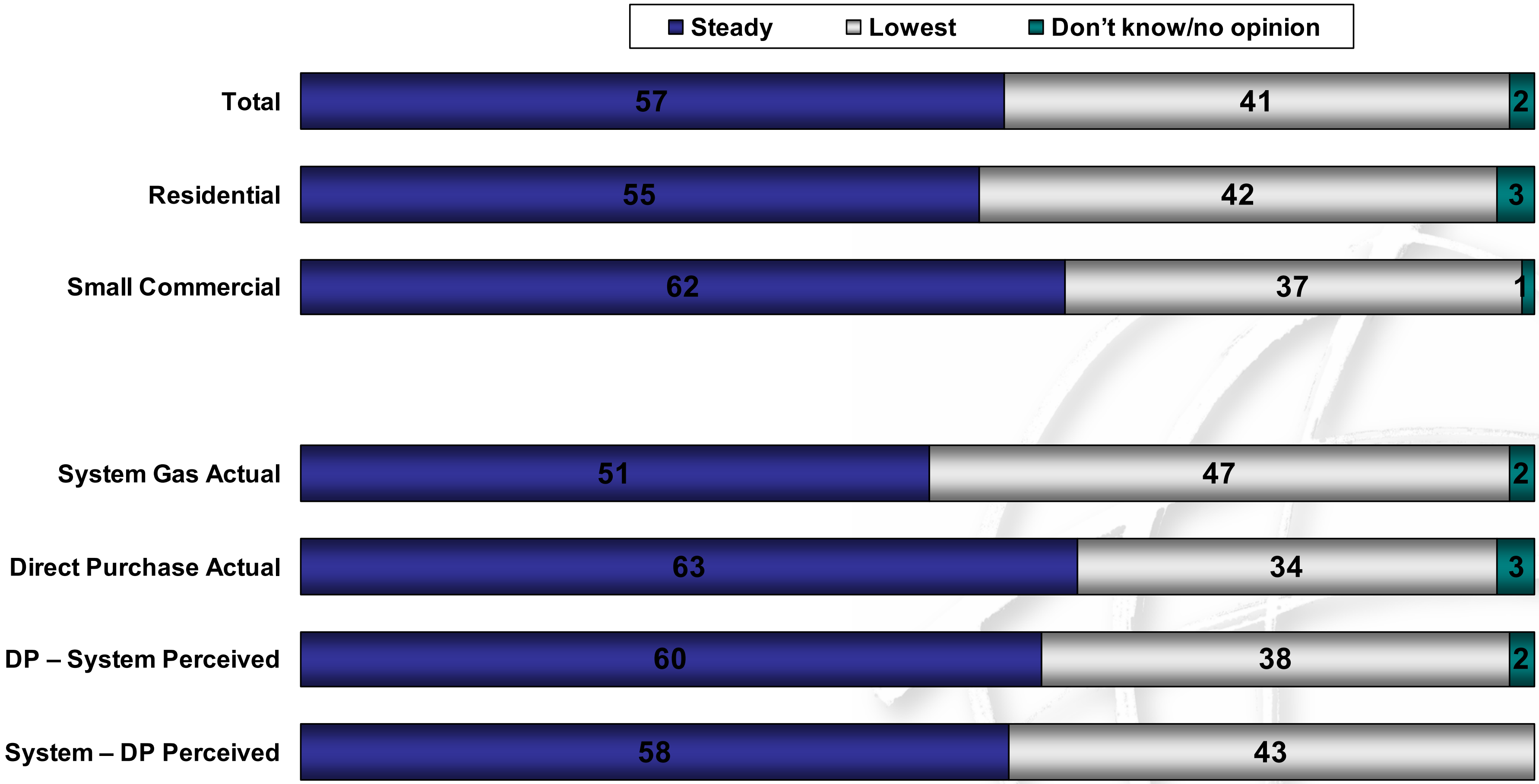
The main reason provided for wanting Enbridge to purchase natural gas at a floating rate is to take advantage of lower prices (28%).

Base: Respondents who said floating rate at Q11	**Total**	**Residential**	**Small Commercial**
N=	497	340	157
To take advantage/ benefit from lower prices	28	28	30
Supply and Demand	17	16	20
Gas prices might go down	13	13	13
The prices are always changing	11	13	9
Stability of pricing/ no fluctuations	7	8	6
The consumer might miss out on cheaper prices	7	8	6
Long term benefit	7	5	10
More fair	6	6	6
Reflects actual cost	5	4	6
Protects you from increasing prices	4	5	3
Can make alternative decision/ option	4	4	4

Q12. And, why do you think they should purchase the natural gas commodity at a floating rate?

Steady Price Versus Lowest Price

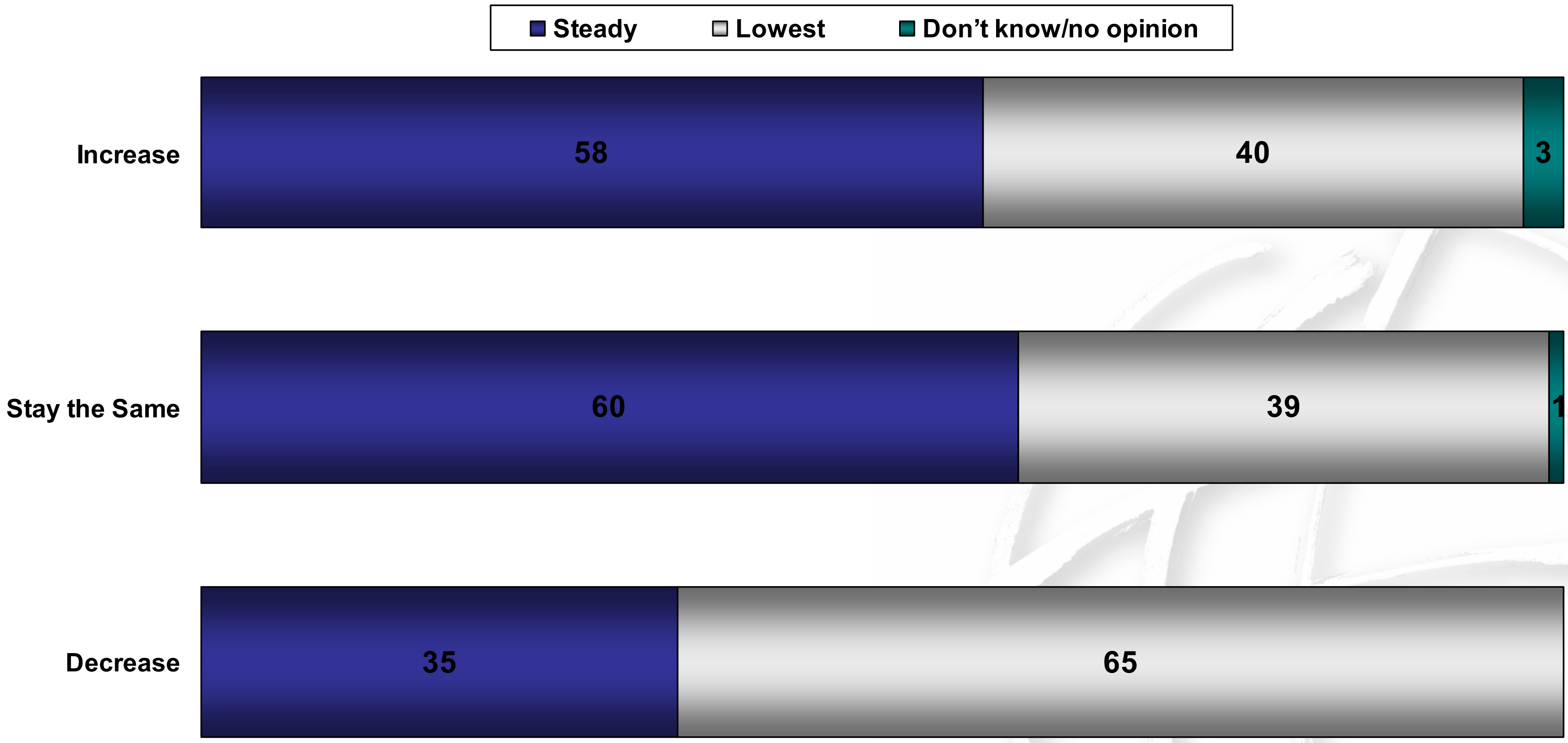
It is more important to maintain a steady price than to try to obtain the lowest price for more than six-in-ten (62%) small commercial customers, somewhat more than residential customers (55%).



Q13. What is more important to you, maintaining a steady price for the natural gas commodity, which may or may not be higher than the market rate or trying to find the lowest price for natural gas commodity even if its means the price will fluctuate more frequently and could result in higher prices?

Steady Price Versus Lowest Price And Perceptions of the Future of Natural Gas Prices

Maintaining a steady price is more important than obtaining the lowest price for significantly more customers who expect the market price of natural gas to increase in the next year than those who expect it to decrease (58% versus 35%).



Q13. What is more important to you, maintaining a steady price for the natural gas commodity, which may or may not be higher than the market rate or trying to find the lowest price for natural gas commodity even if its means the price will fluctuate more frequently and could result in higher prices?

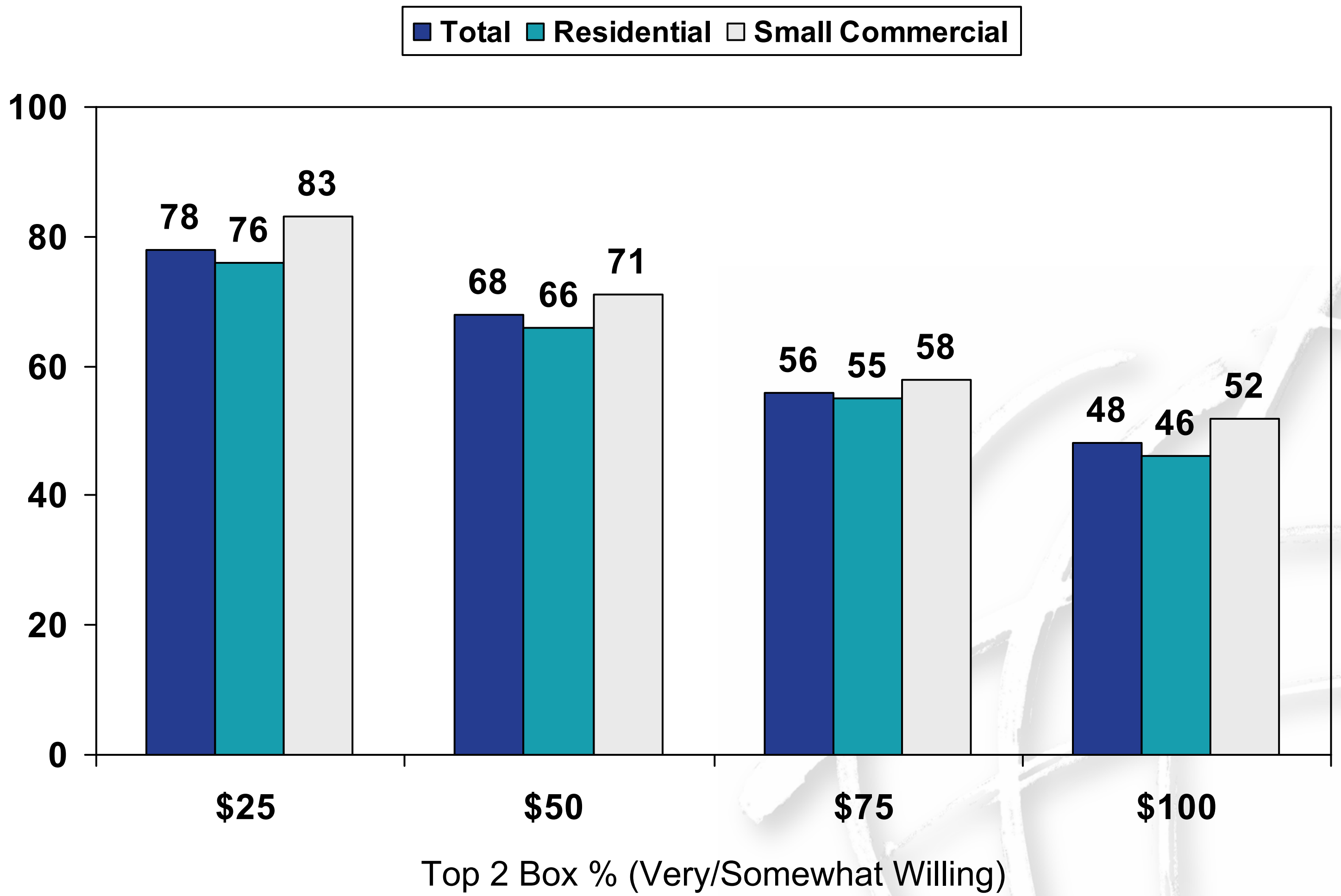
Willingness for Bill Fluctuation

Customers are less willing to accept price fluctuations as the amount of the bill adjustment increases. This is true of both residential and small commercial customers. At the highest level tested ($100), nearly one-half of all customers (48%) reported they would be very or somewhat willing to have the commodity portion of their annual natural gas bill fluctuate by this amount. Small commercial customers are somewhat more willing to accept a fluctuation of $100 than are residential customers (52% versus 46% very/somewhat willing).

	Total				**Residential**				**Small Commercial**			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Net Willing (Top 2 Box %)	78	68	56	48	76	66	55	46	83	71	58	52
Very willing	37	27	18	14	34	24	15	12	42	31	23	17
Somewhat willing	42	41	38	34	42	42	40	33	41	40	36	35
Not very willing	8	14	17	18	9	14	16	18	7	16	19	17
Not at all willing	11	16	25	32	12	18	26	34	8	11	23	30
Don’t know	3	2	2	2	3	2	3	3	2	2	1	1

Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Willingness for Bill Fluctuation



Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Willingness for Bill Fluctuation – System vs. Direct Purchase

Willingness to accept the various bill fluctuations does not vary by customer type (system or direct purchase) or customers' awareness of their supplier.

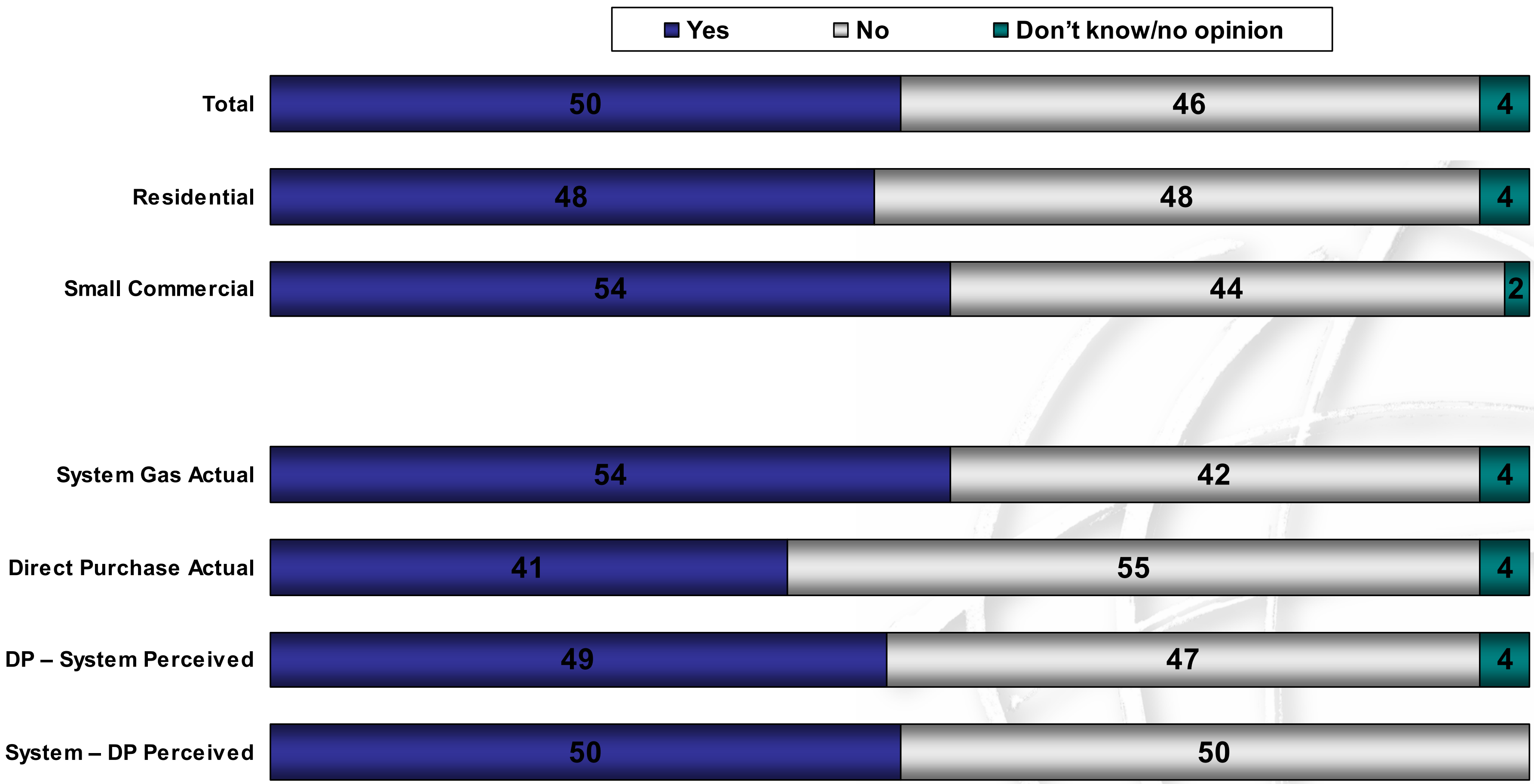
	System Gas Actual				Direct Purchase Actual				DP - System Perceived				System - DP Perceived			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Net Willing (Top 2 Box %)	*77*	*67*	*56*	*48*	*77*	*69*	*55*	*46*	*79*	*69*	*56*	*47*	*90*	*73*	*63*	*50*
Very willing	34	26	17	14	35	23	15	14	38	28	19	13	53	38	28	15
Somewhat willing	43	41	39	34	42	46	40	33	41	41	37	34	38	35	35	35
Not very willing	9	15	16	18	11	14	18	19	7	12	18	19	8	15	15	18
Not at all willing	11	15	25	32	11	17	26	33	12	17	25	33	3	13	23	33
Don't know	4	3	3	3	2	1	1	2	2	1	1	1	-	-	-	-

Q19. Would you be very willing, somewhat willing, not very willing, or not at all willing to have the commodity portion of your annual natural gas bill fluctuate by a maximum of [INSERT ITEM]?

Bill Adjustment Preferences

Awareness of Bill Adjustments

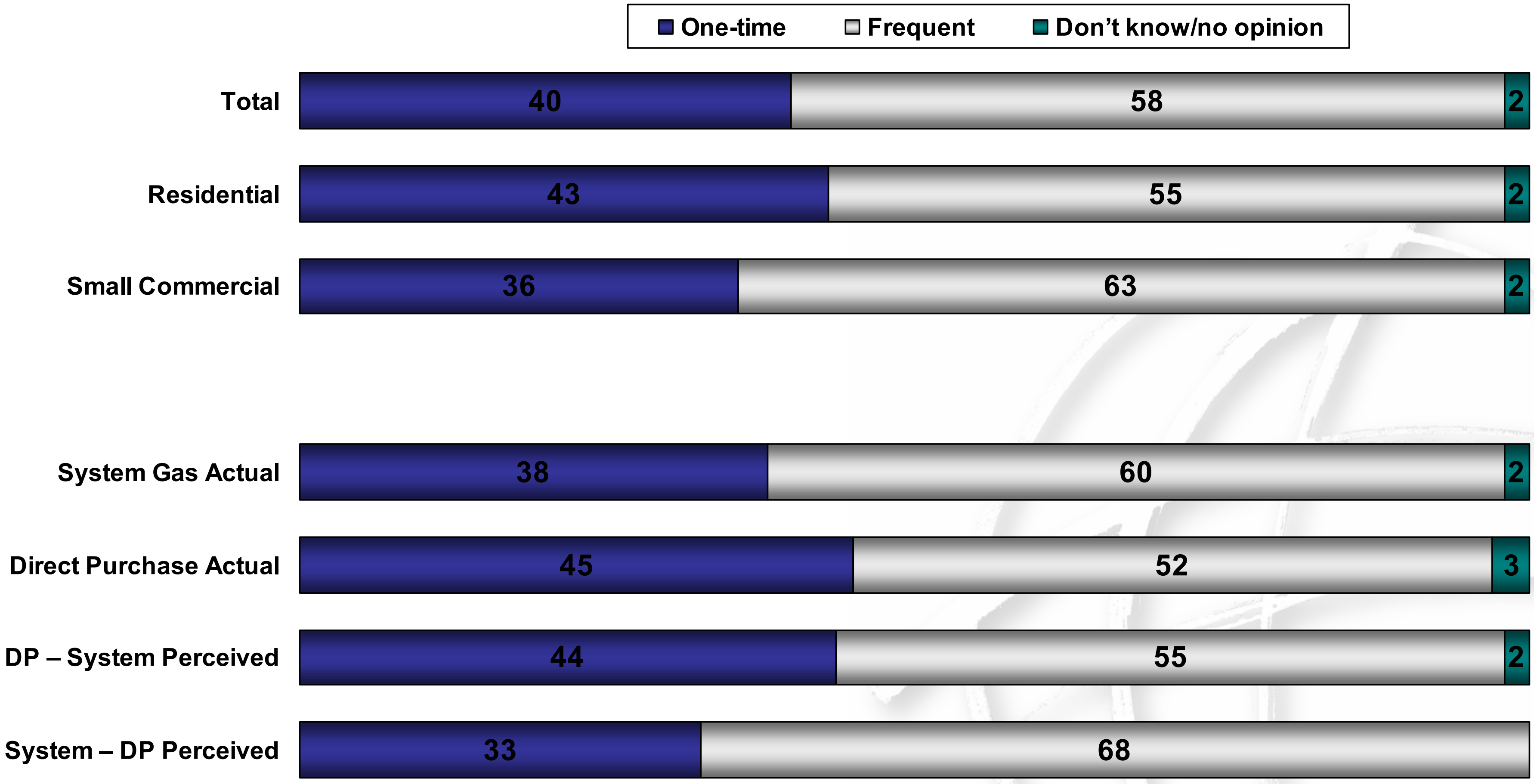
• One-half (50%) of customers report noticing a bill adjustment made to their bill in the past year, with somewhat more small commercial than residential customers noticing the adjustments (54% vs. 48%).
• System gas customers are more likely to report noticing the adjustments than direct purchase customers (54% vs. 41%).



Q20. Have you noticed such an adjustment being made to your bill in the past year?

General Preference for Frequency of Bill Adjustments

In general, about six-in-ten customers (58%) would prefer that Enbridge make smaller, more frequent adjustments to their bill, and four-in-ten (40%) would prefer a one-time, year-end adjustment. More small commercial than residential customers prefer smaller, more frequent adjustment (63% versus 55%).



Q21. Generally speaking, would you prefer that Enbridge make a one-time, year-end adjustment to your bill, or make smaller, more frequent adjustments to your bill?

Ipsos Reid

Frequency of Bill Adjustments

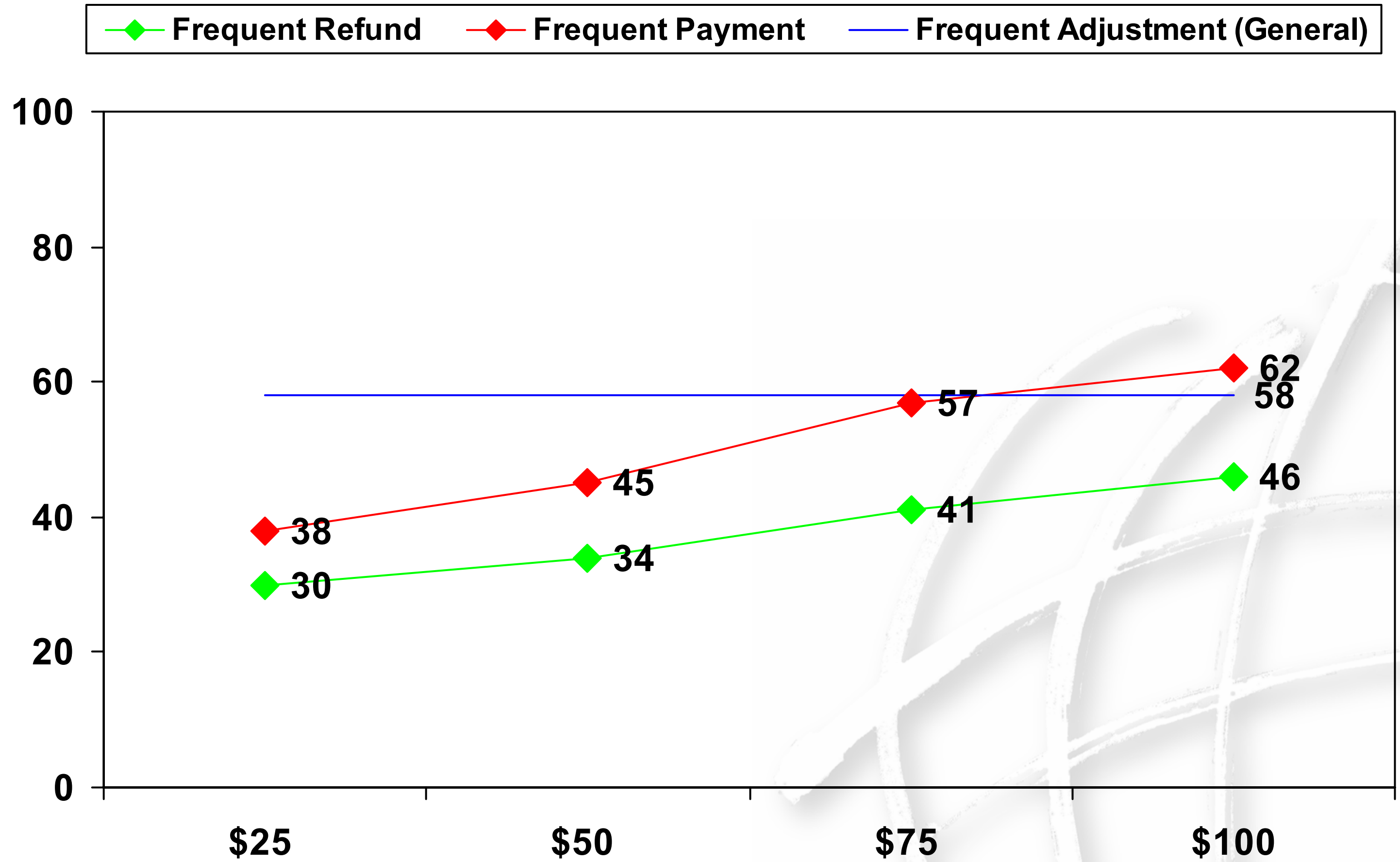
Among customers who would prefer smaller and more frequent adjustments to their bill, most think that the adjustments should be made four times per year (61%).

Base: Respondents who wanted smaller, more frequent adjustments to their bill	Total	Residential	Small Commercial	System Gas Actual	Direct Purchase Actual	DP – System Perceived	System – DP Perceived
N=	691	440	251	313	104	198	27
Twice per year	12	12	11	9	14	17	11
Four times per year	61	60	62	65	59	55	52
Once per month	27	27	27	26	27	28	37
Don't know	-	1	-	-	1	1	-

Q22. And, generally speaking, how frequently do you think Enbridge should make these adjustments to your bill?
Base: Respondents who said they wanted 'smaller, more frequent adjustments' to their bill at Q21.

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

Under both the refund and payment scenarios, the proportion of customers who prefer frequent adjustments increases as the amount of the debit/credit increases. However, proportionately more customers prefer frequent adjustments under the refund scenario than the payment scenario at all adjustment levels.



Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

- Under the refund scenario, there is little difference between residential and small commercial customers in their preference for one-time or frequent adjustments.
- Under the payment scenario, small commercial customers are significantly more likely to prefer a one-time adjustment than residential customers at each adjustment level tested.

	Total				Residential				Small Commercial			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Refund												
One-time adjustment	68	65	57	53	67	64	57	53	71	67	58	53
More frequent adjustments	30	34	41	46	31	35	42	45	28	32	41	46
Don't know	1	1	1	1	2	1	2	1	1	1	1	1
Payment												
One-time adjustment	60	54	42	36	57	50	38	34	66	61	48	40
More frequent adjustments	38	45	57	62	41	48	60	64	33	38	51	59
Don't know	2	2	2	2	2	2	2	2	1	1	2	1

Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

Frequency of Bill Adjustments Based on Refund/Payment Scenarios

There is little variation in preference for one-time or frequent adjustments based on customer type (system or direct purchase) or awareness of supplier.

	System Gas Actual				Direct Purchase Actual				DP – System Perceived				System – DP Perceived			
	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100	$25	$50	$75	$100
Refund																
One-time adjustment	68	64	56	51	71	65	57	55	68	66	59	56	78	75	65	63
More frequent adjustments	31	34	42	48	27	34	41	43	32	34	41	44	23	25	33	38
Don't know	2	2	2	2	2	2	2	2	1	1	1	-	-	-	3	-
Payment																
One-time adjustment	61	55	40	34	60	52	45	38	61	56	44	39	58	58	38	35
More frequent adjustments	37	43	57	64	37	45	52	59	38	44	52	60	43	43	63	65
Don't know	2	2	3	2	3	3	3	3	1	-	3	1	-	-	-	-

Q23. If Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a refund to be paid to you, do you think they should adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?
Q24. And, if Enbridge were to make a total adjustment for the year, in the amount of [INSERT ITEM] which would be a payment to be collected from you, should they adjust your bill for this amount at the end of the year or should they make smaller adjustments throughout the year?

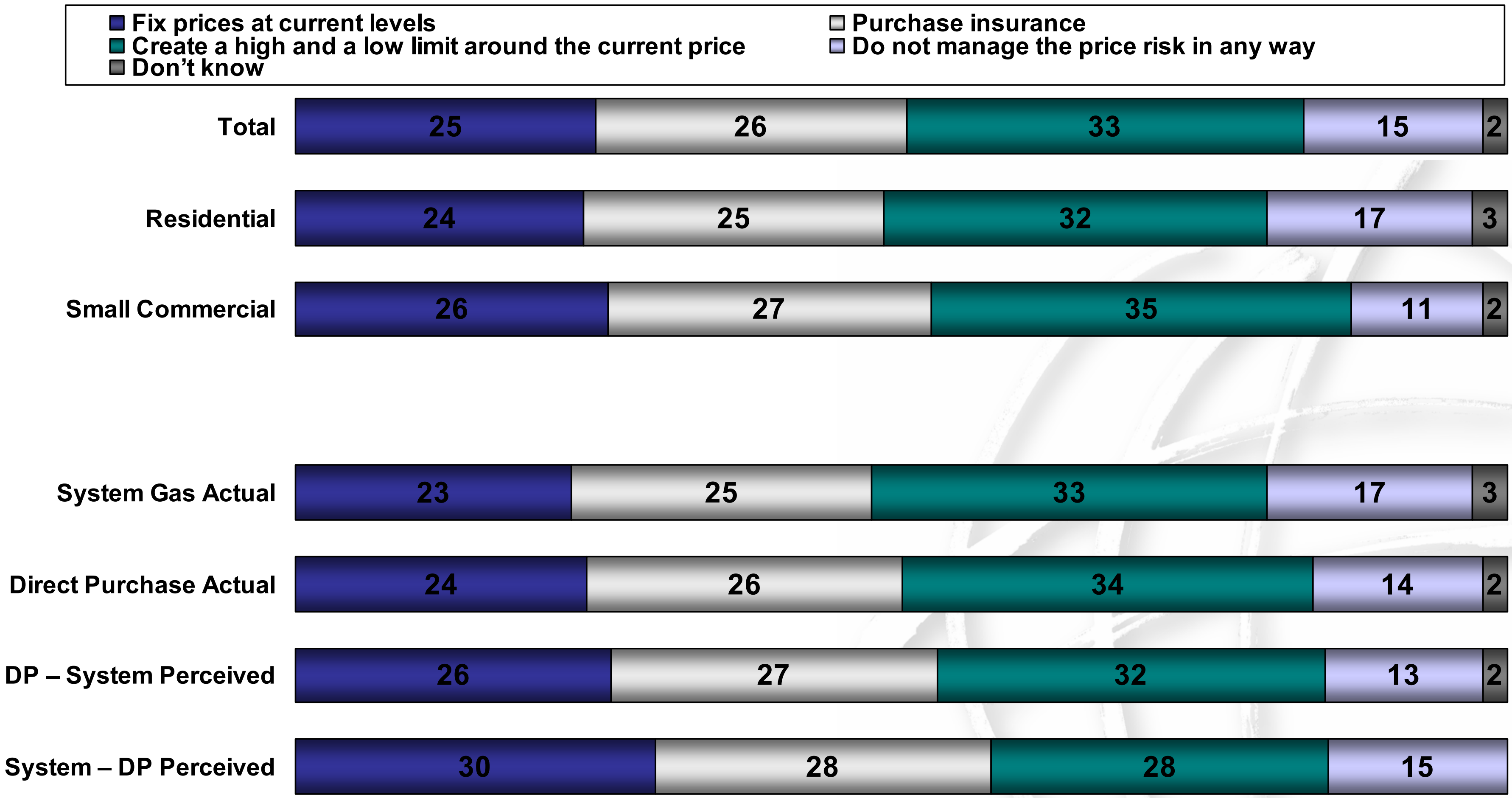
Ipsos Reid

Risk Management

Strategy Preferences

Risk Management Strategy Preference

In general, creating a high and low limit around the current price is the preferred strategy of one-third of customers (33%). The next most preferred approaches, purchase insurance (26%) and fixing prices at current levels (25%) are evenly matched at about one-quarter each. Only about one-in-seven (15%) would not like Enbridge to manage the price risk in any way. These results are consistent for both residential and small commercial customers and across customer types.

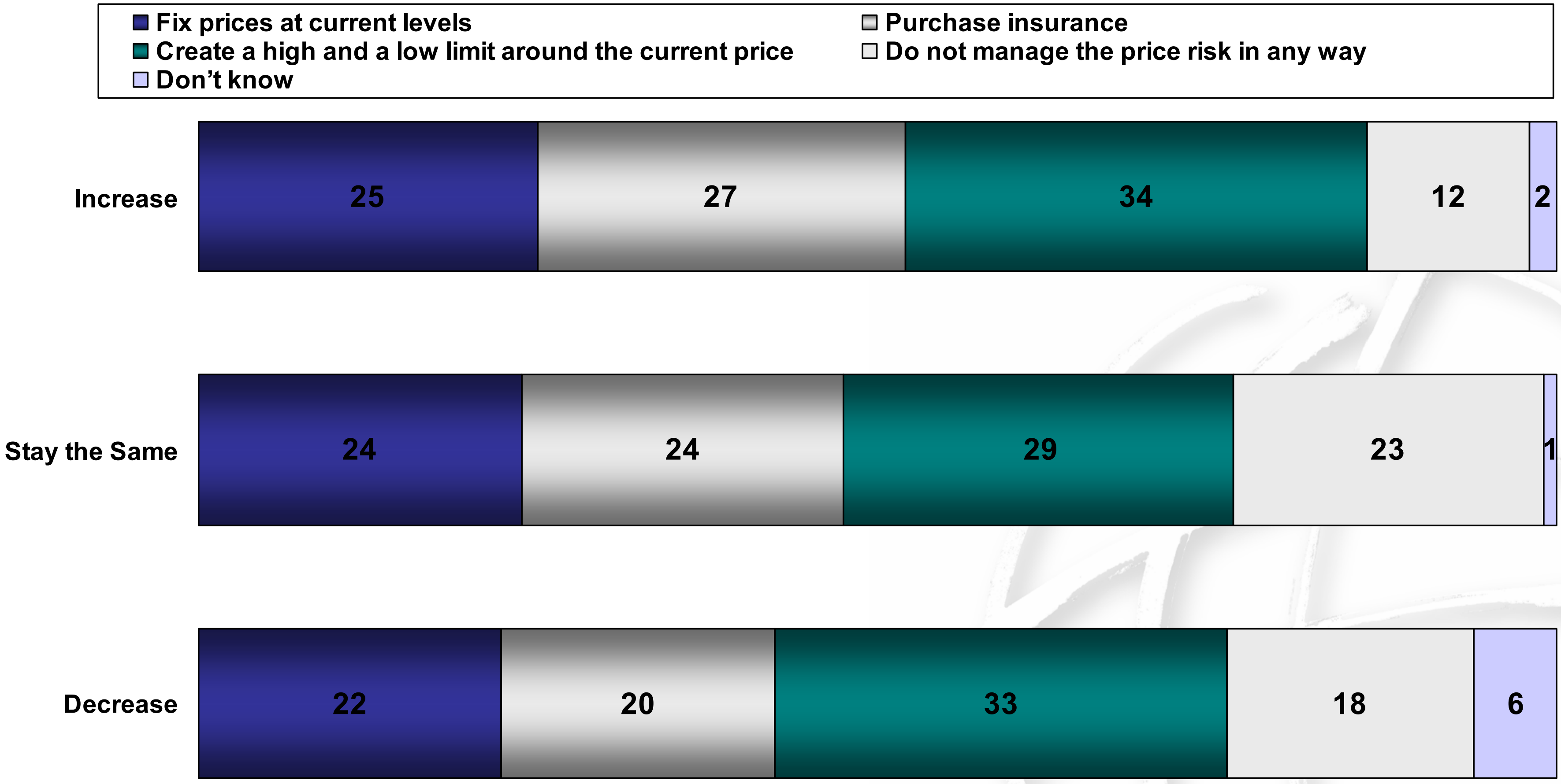


Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?

Ipsos Reid

Risk Management Strategy Preference And Perceptions of the Future of Natural Gas Prices

Customers that expect the market price for natural gas to stay the same over the next year are more likely to prefer that Enbridge not manage the price risk than are those who expect the price to increase (23% versus 12%).



Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?

Strategy Preference Change – Price Decrease

Nearly two-thirds of respondents (64%) who originally stated a preference for Enbridge to fix prices at current levels indicated that a price decrease of 50% would change their response. When provided with the options again, almost one-half (45%) of these chose a strategy that allowed them some benefit from falling prices. Seven percent of those who originally chose an approach that afforded some protection from increasing prices now opted for Enbridge to NOT manage the price risk in any way.

	Fix Prices at Current Levels	Purchase Insurance	Create a High and Low Limit	Do Not Manage the Price Risk
Would a Price Decrease of 50% Change your Preference?				
N=	294	308	396	174
Yes	64	57	50	43
No	33	40	48	53
Don’t know	3	3	2	3
What Pricing Approach Would You Like Enbridge to Use if the Price Decreased by 50%?				
Base: Respondents who said a price decrease of 50% would change their response	188	176	196	75
Fix Prices at Current Levels	54	15	17	16
Purchase Insurance	13	51	14	16
Create a High and Low Limit	24	18	49	19
Do Not Manage the Price Risk	8	13	17	44
Don’t know	2	3	3	5

Q14. Which of these four approaches would you like to see Enbridge use on behalf of its customers?
Q15. If this price decreased 50% to $300, would this change your answer with respect to how you would like to see Enbridge manage the cost of the natural gas commodity on behalf of its customers?
Q16. And, what pricing approach would you like to see Enbridge use on behalf of its customers if the current market price of gas commodity decreased by 50%?

Strategy Preference Change – Price Increase

Interestingly, less than one-third (32%) of customers who preferred that Enbridge not manage the price risk indicated that a price increase of 50% would change their response. Six-in-ten (60%) of these chose a new approach that afforded some protection from increasing prices. More than one-half of those who chose one of the risk management strategies reported that a price increase of 50% would not change their response. In addition, about half of those who stated that a price increase would change their response selected the same pricing approach when provided with the options.

	Fix Prices at Current Levels	Purchase Insurance	Create a High and Low Limit	Do Not Manage the Price Risk
Would a Price Increase of 50% Change your Preference?				
N=	294	308	396	174
Yes	45	42	39	32
No	53	58	59	64
Don't know	3	1	2	4
What Pricing Approach Would You Like Enbridge to Use if the Price Increased by 50%?				
Base: Respondents who said a price increase of 50% would change their response	131	128	154	55
Fix Prices at Current Levels	54	24	25	20
Purchase Insurance	18	46	20	26
Create a High and Low Limit	20	22	46	15
Do Not Manage the Price Risk	5	4	8	35
Don't know	3	4	2	6

Q17. Which of these four approaches would you like to see Enbridge use on behalf of its customers?
Q18. If the current market price of natural gas commodity for the next year increased 50% to approximately $900, would this change your answer with respect to how you would like to see Enbridge manage the cost of the natural gas commodity on behalf of its customers?
Q19. And, what pricing approach would you like to see Enbridge use on behalf of its customers if the current market price of the natural gas commodity increased by 50%?

Original
EB-2005-0001
Exhibit A3
Tab 3
Schedule 1
Attachment

Ipsos Reid

Enbridge Gas Distribution

Customer Threshold for Gas Supply Volatility Study

December 2004

ENBRIDGE

CR-374

K 2.6

Analysis of Revenue to Cost Ratios for Rate 1 with and without Upstream Cost allocation changes implemented in Fiscal 2005

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
		Revenues ($000)	Costs ($000)	Over / (Under) Contribution ($000)	Revenue to Cost Ratios	Phase-in Adjustment ($000)	Over / (Under) Contribution Adjusted ($000)	Revenue to Cost Ratios Adjusted
	2001	747,150	752,910	(5,760)	0.99	20,817	15,057	1.02
	2002	750,610	759,430	(8,820)	0.99	21,020	12,200	1.02
	2003	803,972	813,405	(9,433)	0.99	21,209	11,776	1.01
	2004	n/a	n/a	n/a	n/a	n/a		
	2005	873,830	867,650	6,180	1.01	(8,722)	(2,542)	1.00
	2006	899,330	890,580	8,750	1.01	(5,405)	3,345	1.00
As Filed	2007	956,460	940,950	15,510	1.02	(5,010)	10,500	1.01
ADR @ $26M	2007	855,195	844,839	10,356	1.01	(5,010)	5,346	1.01

Notes:
Col 2 = Approved Revenues excluding Commodity
Col 3 = Approved Costs excluding Commodity
Col 4 = Revenues - Costs
Col 5 = Revenues/Costs
Col 6 = Adjustment to reflect currently approved upstream cost allocation methodology
Impact of full implementation of approved methodology in 2005 = 0.5 c/m3 for Rate 1 customers
Impact for 2001-2003 derived as 0.5 c/m3*Rate 1 volumes
Col 7 = Col 2 + Col 6
Col 8 = Col 2/(Col 3-Col 6) for 2001- 2003
Col 8 = (Col 2+Col 6)/Col 3 for 2005-2007

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K.2.6
DATE January 29, 2007
08/99

Analysis of Revenue to Cost Ratios for Rate 6 with and without Upstream Cost allocation changes implemented in Fiscal 2005

	Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
		Revenues	Costs	Over Contribution	R/C	Phase-in Adjustment	Over Cont. Adjusted	R/C Adjusted
	2001	382,497	375,764	6,733	1.02	15,742	22,475	1.06
	2002	382,469	376,713	5,756	1.02	16,004	21,760	1.06
	2003	397,408	395,259	2,149	1.01	15,599	17,748	1.05
	2004	n/a	n/a	n/a	n/a	n/a		
	2005	415,635	405,317	10,318	1.03	(8,722)	1,596	1.00
	2006	414,114	409,920	4,194	1.01	(5,181)	(987)	1.00
As Filed	2007	407,811	405,126	2,685	1.01	(4,892)	(2,207)	0.99
ADR@$26M	2007	373,847	368,783	5,064	1.01	(4,892)	172	1.00

Notes:
Col 2 = Approved Revenues excluding Commodity
Col 3 = Approved Costs excluding Commodity
Col 4 = Revenues - Costs
Col 5 = Revenues/Costs
Col 6 = Adjustment to reflect currently approved upstream cost allocation methodology
Impact of full implementation of approved methodology in 2005 = 0.5 c/m3 for Rate 6 customers
Impact for 2001-2003 derived as 0.5 c/m3*Rate 6 volumes
Col 7 = Col 2 + Col 6
Col 8 = Col 2/(Col 3-Col 6) for 2001- 2003
Col 8 = (Col 2+Col 6)/Col 3 for 2005-2007

K 3.1

VECC INTERROGATORY #73

INTERROGATORY

Reference: Ex. G2, Tab 2, Sch. 1, and Sch. 2, page 1

Request: a) Please provide the Revenue to Cost Rate of Return Comparison tables (Sch. 1 and Sch. 2) for the last 5 Rate Applications that were approved by the Board.

b) Please provide the Revenue to Cost ratios for distribution only (i.e., exclusive of gas supply commodity, gas supply load balancing, and transportation) by rate class for the last 5 years and the 2006 test year.

c) How is the return on rate base per rate class derived?

d) In rate making does Enbridge attempt to maintain consistent return of rate base for each rate class over the years?

e) Why is it reasonable that the Rates 115, 135, and 170, have a negative return on rate base?

RESPONSE

a) Revenue to Cost Exhibits (Schedules 1 and 2) as approved by the Board are provided herein as Attachment A for:
- 2005
- 2003
- 2002
- 2001

Note: 2004 was not a cost-of-service year. Schedules not attached.

b) Distribution Only Revenue to Cost Exhibits (Schedules 1 and 2) are provided herein as Attachment B for:
- 2006
- 2005
- 2003
- 2002
- 2001

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K.3.1
DATE January 30, 2007
08/99

Note: 2004 was not a cost-of-service year. Schedules not attached.

c) The return on rate base per rate class is derived by taking the return allocated to the rate class (Exhibit G2, Tab 5, Schedule 3, p. 1, Line 6.1, Col. 4) and the return component of the rate class over/under contribution (Exhibit G2, Tab 2, Schedule 1, p. 1, Line 5, Col. 2) divided by the rate base allocated to the rate class (Exhibit G2, Tab 2, Schedule 1, p. 1, Line 7, Col. 2).

The derivation for Rate 1 is provided below to help illustrate the return on rate base calculation.

(\$186.67 + \$1.06 * \$284.34 / \$363.37) / \$2239.35 = 0.0837 = <u>8.37%</u>

The derivation of the return on rate base per rate class, excluding gas supply commodity, follows the approach outlined above, but excludes commodity-related return.

d) In designing rates the Company follows established rate making principles including:

- cost causality (rates to be based on costs incurred to provide service to the
- rate classes);
- minimize cross-subsidization;
- promote market acceptance; and
- minimize rate shock.

The Company endeavors to maintain consistent revenue to cost ratios for each rate class on a year to year basis, while balancing the other objectives mentioned above.

e) The negative return on rate base for Rates 115, 135, and 170 for 2006 is a consequence of the phased implementation of the cost allocation changes and will disappear once these changes are fully implemented.

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2005

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,889.96	1,671.18	850.59	4.30	160.54	44.94	42.44	2.69	26.32	43.14	40.29	0.00	0.07	0.08	1.83	1.56
2.	Unbilled Revenues	1.65	1.08	0.46	0.00	0.12	(0.02)	(0.01)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,891.62	1,672.25	851.05	4.30	160.66	44.93	42.44	2.69	26.33	43.14	40.29	0.00	0.07	0.08	1.83	1.56
4.	Cost of Service	2,891.62	1,666.07	840.73	4.60	162.37	45.87	50.73	3.28	25.95	48.30	40.24	0.00	0.00	0.10	1.80	1.56
5.	Over/Under Contribution	0.00	6.19	10.32	(0.31)	(1.71)	(0.95)	(8.30)	(0.59)	0.38	(5.16)	0.05	0.00	0.07	(0.02)	0.03	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.34	3.10	(23.84)	(1.22)	(1.52)	(8.95)	(10.08)	1.23	(8.29)	0.27	0.00	0.00	(1.50)	N/A	N/A
7.	Rate Base	3,422.10	2,121.73	769.47	8.79	200.53	38.30	22.33	1.85	22.48	15.61	9.73	0.00	0.00	0.35	190.93	
8.	Return on Rate Base	8.12%	8.35%	9.14%	5.37%	7.45%	6.19%	-21.04%	-16.96%	9.47%	-17.81%	8.52%	0.00%	0.00%	3.74%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.00	1.01	0.93	0.99	0.98	0.84	0.82	1.01	0.89	1.00	0.00	0.00	0.81	1.01	N/A

Final Board Order
Filed: 2004-11-22
RP-2003-0203
Exhibit G3
Tab 2
Schedule 1
Page 1 of 1

**REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2005**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,568.28	872.75	415.17	1.71	131.59	40.23	42.44	2.21	20.02	27.64	10.99	0.00	0.07	0.08	1.83	1.56
2.	Unbilled Revenues	1.65	1.08	0.46	0.00	0.12	(0.02)	(0.01)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,569.93	873.83	415.64	1.71	131.71	40.21	42.44	2.21	20.03	27.64	10.99	0.00	0.07	0.08	1.83	1.56
4.	Cost of Service	1,569.93	867.65	405.32	2.02	133.41	41.16	50.73	2.80	19.65	32.80	10.94	0.00	0.00	0.10	1.80	1.56
5.	Over/Under Contribution	(0.00)	6.18	10.32	(0.31)	(1.71)	(0.95)	(8.30)	(0.59)	0.38	(5.17)	0.05	0.00	0.07	(0.02)	0.03	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m³)		1.34	3.10	(23.81)	(1.22)	(1.52)	(6.95)	(10.09)	1.23	(6.29)	0.27	0.00	0.00	0.00	N/A	
7.	Rate Base	3,408.12	2,113.28	784.88	8.76	200.22	38.25	22.33	1.85	22.41	15.44	9.41	0.00	0.00	0.35	190.93	0.00
8.	Indicated Return on Rate Base	8.12%	8.35%	9.15%	5.36%	7.45%	8.19%	-21.04%	-17.04%	9.47%	-18.09%	8.53%	0.00%	0.00%	3.74%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.03	0.85	0.99	0.98	0.84	0.79	1.02	0.84	1.00	0.00	0.00	0.81	1.01	N/A

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2003

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,267.92	1,281.14	663.33	2.05	139.01	39.54	39.07	3.66	22.81	37.54	35.93	0.00	0.01	0.06	2.22	1.56
2.	Unbilled Revenues	0.01	0.09	(0.53)	0.00	0.22	0.23	(0.20)	(0.03)	0.57	(0.33)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,267.94	1,281.23	662.80	2.05	139.23	39.77	38.87	3.63	23.37	37.21	35.93	0.00	0.01	0.06	2.22	1.56
4.	Cost of Service	2,267.94	1,290.66	660.65	2.13	137.64	38.16	37.57	2.76	22.10	36.92	35.59	0.00	0.00	0.06	2.12	1.58
5.	Over/Under Contribution	(0.00)	(9.43)	2.15	(0.08)	1.59	1.61	1.29	0.87	1.27	0.29	0.34	0.00	0.01	(0.00)	0.10	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m³)		(2.22)	0.69	(6.32)	1.14	2.45	1.38	8.97	4.23	0.35	1.81	0.00	0.00	(0.62)	N/A	N/A
7.	Rate Base	3,155.80	1,949.29	737.13	9.41	171.18	40.68	22.04	2.18	22.50	16.13	7.05	0.00	0.00	0.20	178.02	
8.	Return on Rate Base	8.32%	7.95%	8.54%	7.66%	9.02%	11.31%	12.74%	36.36%	12.58%	9.66%	12.00%	0.00%	0.00%	6.52%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.00	0.96	1.01	1.04	1.04	1.33	1.06	1.01	1.01	0.00	0.00	0.92	1.05	N/A

Filed: 2003-04-02
Final Board Order
RP-2002-0133
Exhibit G2
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Attachment A

ENBRIDGE

REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2003

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,456.82	803.88	397.94	1.65	117.86	37.69	39.07	3.66	17.14	24.29	9.80	0.00	0.01	0.06	2.22	1.56
2.	Unbilled Revenues	0.01	0.09	(0.53)	0.00	0.22	0.23	(0.20)	(0.03)	0.57	(0.33)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,456.84	803.97	397.41	1.65	118.08	37.92	38.87	3.63	17.70	23.96	9.80	0.00	0.01	0.06	2.22	1.56
4.	Cost of Service	1,456.84	813.40	395.26	1.73	116.49	36.31	37.57	2.76	16.43	23.67	9.46	0.00	0.00	0.06	2.12	1.58
5.	Over/Under Contribution	0.00	(9.43)	2.15	(0.08)	1.59	1.61	1.29	0.87	1.27	0.29	0.34	0.00	0.01	(0.00)	0.10	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.22)	0.69	(6.35)	1.14	2.45	1.38	8.99	4.24	0.35	1.81	0.00	0.00	0.00	N/A	
7.	Rate Base	3,136.29	1,937.80	730.76	9.40	170.67	40.63	22.04	2.18	22.36	15.81	6.42	0.00	0.00	0.20	178.02	0.00
8.	Indicated Return on Rate Base	8.32%	7.95%	8.54%	7.66%	9.02%	11.31%	12.74%	38.42%	12.61%	9.69%	12.36%	0.00%	0.00%	6.52%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.01	0.95	1.01	1.04	1.03	1.31	1.08	1.01	1.04	0.00	0.00	0.92	1.05	N/A

ENBRIDGE

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2002**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,242.54	1,225.55	677.37	2.25	151.39	43.23	40.37	4.03	26.23	35.69	32.98	0.08	0.02	0.05	2.20	1.12
2.	Unbilled Revenues	(3.29)	(1.63)	(0.72)	0.00	(0.44)	(0.13)	(0.17)	(0.01)	(0.08)	(0.12)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,239.25	1,223.93	676.65	2.25	150.95	43.10	40.20	4.02	26.14	35.57	32.98	0.08	0.02	0.05	2.20	1.12
4.	Cost of Service	2,239.25	1,232.76	670.89	2.21	151.43	42.48	39.28	2.92	25.67	35.53	32.72	0.07	0.00	0.06	2.09	1.15
5.	Over/Under Contribution	0.00	(8.83)	5.76	0.04	(0.48)	0.62	0.92	1.10	0.47	0.04	0.26	0.01	0.02	(0.01)	0.11	(0.03)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.10)	1.80	2.80	(0.34)	1.02	1.00	11.88	1.43	0.05	1.43	3.41	0.00	(1.57)	N/A	N/A
7.	Rate Base	3,019.30	1,825.17	675.44	10.10	172.94	49.06	42.36	2.26	27.28	28.91	8.75	0.24	0.00	0.21	176.56	
8.	Return on Rate Base	8.26%	7.90%	8.90%	8.59%	8.06%	9.21%	9.88%	44.47%	9.56%	8.36%	10.47%	11.37%	0.00%	3.82%	10.31%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.01	1.02	1.00	1.01	1.03	1.38	1.02	1.00	1.01	1.15	0.00	0.80	1.05	N/A

ENBRIDGE
Consumers Gas

**REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2002**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,386.66	752.23	383.19	1.71	114.88	35.68	39.94	3.49	18.65	23.90	9.54	0.08	0.02	0.05	2.20	1.12
2.	Unbilled Revenues	(3.29)	(1.63)	(0.72)	0.00	(0.44)	(0.13)	(0.17)	(0.01)	(0.08)	(0.12)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,383.37	750.61	382.47	1.71	114.44	35.55	39.78	3.48	18.56	23.78	9.54	0.08	0.02	0.05	2.20	1.12
4.	Cost of Service	1,383.37	759.43	376.71	1.66	114.92	34.93	38.86	2.38	18.09	23.74	9.28	0.07	0.06	0.06	2.09	1.15
5.	Over/Under Contribution	0.00	(8.83)	5.76	0.04	(0.48)	0.62	0.92	1.10	0.48	0.04	0.26	0.01	(0.04)	(0.01)	0.11	(0.03)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(2.10)	1.80	2.81	(0.34)	1.02	1.00	11.88	1.43	0.05	1.43	0.00	0.00	0.00	N/A	
7.	Rate Base	2,995.67	1,811.99	667.25	10.08	171.93	48.86	42.35	2.25	27.07	28.58	8.10	0.24	0.21	0.21	176.56	0.00
8.	Indicated Return on Rate Base	8.26%	7.90%	8.90%	8.59%	8.05%	9.21%	9.88%	44.71%	9.57%	8.36%	10.65%	11.37%	-7.39%	3.82%	10.31%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.02	1.03	1.00	1.02	1.02	1.46	1.03	1.00	1.03	1.15	0.28	0.80	1.05	N/A

ENBRIDGE Consumers Gas

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2001**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 310	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Trans. Revenue	2,728.04	1,490.84	810.05	3.47	193.81	52.38	42.78	3.93	40.29	43.85	42.85	0.30	0.00	2.41	1.07
2.	Unbilled Revenues	12.09	7.12	3.80	0.00	0.48	0.23	0.08	0.03	0.12	0.23	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	2,740.13	1,497.96	813.84	3.47	194.29	52.62	42.86	3.96	40.41	44.08	42.85	0.30	0.00	2.41	1.07
4.	Cost of Service	2,740.13	1,503.72	807.11	2.98	195.25	52.43	42.98	3.40	40.94	45.01	42.86	0.10	0.00	2.26	1.09
5.	Over/Under Contribution	(0.00)	(5.76)	6.73	0.49	(0.95)	0.19	(0.12)	0.56	(0.53)	(0.93)	(0.02)	0.20	0.00	0.15	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(1.38)	2.14	26.47	(0.67)	0.31	(0.12)	7.80	(1.50)	(1.07)	(0.07)	56.16	0.00	N/A	N/A
7.	Rate Base	3,118.20	1,842.13	708.35	11.09	195.93	52.65	52.24	1.87	36.16	39.08	13.25	0.37	0.00	165.06	
8.	Return on Rate Base	8.54%	8.31%	9.24%	11.81%	8.19%	8.80%	8.37%	30.80%	7.47%	6.80%	8.46%	48.10%	0.00%	10.83%	N/A
9.	Revenue to Cost Ratio	1.00	1.00	1.01	1.17	1.00	1.00	1.00	1.16	0.99	0.98	1.00	2.98	0.00	1.07	N/A

ENBRIDGE
Consumers Gas

**REVENUE TO COST/
RATE OF RETURN COMPARISONS
EXCLUDING GAS SUPPLY COMMODITY
SEPT. 30, 2001**

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 310	RATE 325 & 330	DIRECT PURCHASE
1.	Sales and Trans. Revenue	1,383.80	740.03	378.70	2.06	119.14	35.09	42.78	2.84	21.39	27.45	10.72	0.30	0.00	2.41	1.07
2.	Unbilled Revenues	12.09	7.12	3.80	0.00	0.48	0.23	0.08	0.03	0.12	0.23	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	1,395.88	747.15	382.50	2.06	119.63	35.33	42.88	2.88	21.51	27.68	10.72	0.30	0.00	2.41	1.07
4.	Cost of Service	1,395.89	752.91	375.78	1.56	120.58	35.14	42.98	2.11	22.04	28.61	10.73	0.10	0.00	2.26	1.09
5.	Over/Under Contribution	(0.00)	(5.76)	6.73	0.49	(0.95)	0.19	(0.12)	0.56	(0.53)	(0.93)	(0.02)	0.20	0.00	0.15	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		(1.38)	2.14	26.45	(0.67)	0.32	(0.12)	7.80	(1.50)	(1.07)	(0.07)	0.00	0.00	N/A	
7.	Rate Base	3,078.36	1,819.87	696.58	11.05	193.72	52.14	52.24	1.83	36.60	38.60	12.30	0.37	0.00	165.06	0.00
8.	Indicated Return on Rate Base	8.54%	8.31%	9.25%	11.82%	8.18%	8.80%	8.37%	31.05%	7.45%	6.78%	8.45%	48.10%	0.00%	10.83%	N/A
9.	Revenue to Cost Ratio	1.00	0.99	1.02	1.32	0.99	1.01	1.00	1.27	0.98	0.97	1.00	2.98	0.00	1.07	N/A

ENBRIDGE Consumers Gas

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2006

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	992.63	661.41	234.28	0.93	58.71	11.96	9.01	0.78	4.56	3.41	2.30	0.00	0.01	0.17	1.86	3.27
2.	Unbilled Revenues	(1.55)	(1.06)	(0.49)	0.00	(0.00)	(0.00)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	991.08	660.35	233.79	0.93	58.71	11.95	9.01	0.78	4.56	3.41	2.30	0.00	0.01	0.17	1.86	3.27
4.	Cost of Service	991.08	652.30	235.40	1.40	63.40	11.91	8.17	0.49	4.78	4.99	2.92	0.00	0.00	0.19	1.83	3.27
5.	Over/Under Contribution	(0.00)	8.05	(1.61)	(0.47)	(4.70)	0.05	0.84	0.28	(0.22)	(1.58)	(0.62)	0.00	0.01	(0.02)	0.03	0.00
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.75	(0.50)	(49.95)	(3.32)	0.07	0.81	5.02	(0.88)	(2.05)	(4.02)	0.00	0.00	(0.79)	N/A	N/A
7.	Rate Base	3,603.87	2,239.35	829.06	8.85	215.68	41.66	26.13	1.60	18.52	19.38	10.09	0.00	0.00	0.67	192.87	N/A
8.	Return on Rate Base	6.89%	7.17%	6.73%	2.75%	5.16%	6.97%	9.39%	20.41%	5.95%	0.52%	2.05%	0.00%	0.00%	4.11%	8.59%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	0.99	0.67	0.93	1.00	1.10	1.57	0.95	0.68	0.79	0.00	0.00	0.87	1.02	1.00

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2005**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	908.45	601.23	216.09	1.16	54.23	11.27	8.40	0.80	5.52	4.00	2.20	0.00	0.07	0.08	1.83	1.56
2.	Unbilled Revenues	1.65	1.08	0.46	0.00	0.12	(0.02)	(0.01)	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	910.10	602.31	216.55	1.16	54.35	11.25	8.40	0.80	5.54	4.00	2.20	0.00	0.07	0.08	1.83	1.56
4.	Cost of Service	910.10	593.99	221.27	1.27	58.85	10.87	7.08	0.56	5.78	4.27	2.71	0.00	0.00	0.09	1.80	1.56
5.	Over/Under Contribution	0.00	8.32	(4.71)	(0.11)	(4.50)	0.38	1.31	0.24	(0.25)	(0.27)	(0.51)	0.00	0.07	(0.01)	0.03	(0.00)
6.	Over/Under Contribution ($ PER 10^3 m^3)		1.80	(1.42)	(8.28)	(3.21)	0.61	1.41	4.11	(0.80)	(0.33)	(2.96)	0.00	0.00	(1.01)	N/A	N/A
7.	Rate Base	3,422.10	2,121.73	789.47	8.79	200.53	38.30	22.33	1.85	22.48	15.61	9.73	0.00	0.00	0.35	190.93	
8.	Return on Rate Base	6.69%	7.00%	6.22%	5.73%	4.92%	7.49%	11.38%	16.98%	5.84%	5.41%	2.60%	0.00%	0.00%	3.74%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	0.98	0.92	0.92	1.04	1.19	1.43	0.96	0.94	0.81	0.00	0.00	0.86	1.01	N/A

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2003**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	870.55	559.40	209.54	1.28	51.54	15.05	12.09	1.74	7.12	6.24	2.71	0.00	0.01	0.06	2.22	1.56
2.	Unbilled Revenues	0.01	0.09	(0.53)	0.00	0.22	0.23	(0.20)	(0.03)	0.57	(0.33)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	870.57	559.49	209.01	1.28	51.76	15.28	11.89	1.71	7.68	5.91	2.71	0.00	0.01	0.06	2.22	1.56
4.	Cost of Service	870.57	559.39	212.10	1.22	53.05	13.84	10.31	0.81	7.00	6.36	2.76	0.00	0.00	0.06	2.12	1.58
5.	Over/Under Contribution	(0.00)	0.10	(3.10)	0.06	(1.28)	1.44	1.58	0.90	0.69	(0.46)	(0.05)	0.00	0.01	(0.00)	0.10	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		0.02	(0.89)	5.03	(0.92)	2.19	1.68	9.31	2.29	(0.56)	(0.25)	0.00	0.00	(0.19)	N/A	N/A
7.	Rate Base	3,155.80	1,949.29	737.13	9.41	171.18	40.68	22.04	2.18	22.50	16.13	7.05	0.00	0.00	0.20	178.02	
8.	Return on Rate Base	7.07%	7.07%	6.75%	7.59%	6.50%	9.74%	12.47%	38.24%	9.37%	4.92%	6.57%	0.00%	0.00%	6.52%	9.63%	N/A
9.	Revenue to Cost Ratio	1.00	1.00	0.99	1.05	0.98	1.10	1.17	2.16	1.10	0.93	0.98	0.00	0.00	0.98	1.05	N/A

REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2002

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 300 CDS	Col. 14 RATE 305	Col. 15 RATE 325 & 330	Col. 16 DIRECT PURCHASE
1.	Distribution Revenue	830.86	528.52	204.31	1.24	49.30	13.90	11.96	1.69	7.81	6.03	2.64	0.08	0.02	0.05	2.20	1.12
2.	Unbilled Revenues	(3.29)	(1.63)	(0.72)	0.00	(0.44)	(0.13)	(0.17)	(0.01)	(0.08)	(0.12)	0.00	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	827.57	526.90	203.59	1.24	48.87	13.78	11.79	1.68	7.72	5.91	2.64	0.08	0.02	0.05	2.20	1.12
4.	Cost of Service	827.57	524.06	201.41	1.07	51.96	14.06	12.33	0.68	7.98	7.77	2.91	0.06	0.00	0.06	2.09	1.15
5.	Over/Under Contribution	0.00	2.83	2.18	0.18	(3.09)	(0.28)	(0.54)	0.99	(0.26)	(1.86)	(0.27)	0.01	0.02	(0.01)	0.11	(0.03)
6.	Over/Under Contribution ($ PER 10^3 m^3)		0.67	0.68	11.14	(2.22)	(0.46)	(0.56)	10.76	(0.78)	(2.30)	(1.47)	4.82	0.00	(1.12)	N/A	N/A
7.	Rate Base	3,019.30	1,825.17	675.44	10.10	172.94	49.08	42.36	2.26	27.28	28.91	8.75	0.24	0.00	0.21	176.56	
8.	Return on Rate Base	6.98%	7.09%	7.22%	8.29%	5.64%	6.55%	6.03%	39.75%	6.27%	2.19%	4.69%	11.37%	0.00%	3.82%	10.31%	N/A
9.	Revenue to Cost Ratio	1.00	1.01	1.01	1.17	0.94	0.98	0.97	2.47	0.97	0.76	0.91	1.22	0.00	0.85	1.05	N/A

**REVENUE TO COSTS/
RATE OF RETURN COMPARISONS
SEPT. 30, 2001**

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 135	Col. 9 RATE 145	Col. 10 RATE 170	Col. 11 RATE 200	Col. 12 RATE 300	Col. 13 RATE 310	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Distribution Revenue	804.74	508.54	196.63	1.50	49.60	13.42	12.69	1.18	8.24	6.31	2.86	0.30	0.00	2.41	1.07
2.	Unbilled Revenues	12.09	7.12	3.80	0.00	0.48	0.23	0.08	0.03	0.12	0.23	0.00	0.00	0.00	0.00	0.00
3.	Total Revenues	816.83	515.66	200.42	1.50	50.08	13.66	12.77	1.21	8.36	6.54	2.86	0.30	0.00	2.41	1.07
4.	Cost of Service	816.83	504.74	198.40	0.79	54.86	14.73	15.23	0.72	9.92	10.22	3.78	0.09	0.00	2.26	1.09
5.	Over/Under Contribution	0.00	10.92	2.02	0.70	(4.78)	(1.08)	(2.46)	0.49	(1.56)	(3.69)	(0.92)	0.21	0.00	0.15	(0.02)
6.	Over/Under Contribution ($ PER 10^3 m^3)		2.62	0.64	37.78	(3.35)	(1.83)	(2.51)	6.84	(4.40)	(4.26)	(4.42)	58.81	0.00	N/A	N/A
7.	Rate Base	3,118.20	1,842.13	708.35	11.09	195.93	52.65	52.24	1.87	36.16	39.08	13.25	0.37	0.00	165.06	
8.	Return on Rate Base	6.68%	7.11%	6.89%	11.33%	4.89%	5.18%	3.22%	26.02%	3.52%	-0.24%	1.57%	48.10%	0.00%	10.83%	N/A
9.	Revenue to Cost Ratio	1.00	1.02	1.01	1.89	0.91	0.93	0.83	1.64	0.84	0.64	0.76	3.28	0.00	1.07	N/A

K 4.1

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.1
DATE February 1, 2007
08/99

Enbridge Gas Distribution Inc.

2007 Test Year
Approximate elements of
Changes in volumes & storage
Deficiency Amounts

Line No.		Col. 1 Filed: 2006-08-15 A2.T5.S1 Column 2 ($millions)	Col. 2 Filed: 2007-01-24 A2.T5.S2 Column 2 ($millions)
1.	Gross deficiency amount	22.2	16.1
	Approximate elements		
2.	Degree Days deficiency 20 year trend	12.9	12.9
3.	Average use deficiency	7.3	7.3
4.	Contract volumes deficiency	1.5	1.5
5.	Storage and transportation change deficiency	8.7	2.6
6.	Customer add volume growth sufficiency & other	(8.2)	(8.2)
7.	Changes in volumes and storage deficiency	22.2	16.1

Note:

The potential $ 5 million revenue sufficiency quoted on page 11 of the Settlement Proposal was achieved as follows.

a) In Exhibit N1, Tab 2, Schedule 2, page 2 of 2 of the Settlement Proposal, a remaining deficiency related to unresolved issues of $ 52.1 million is shown.

b) If each of lines 2, 3 & 4 on that page 2 are denied by the Board, the deficiency would decline to the $ 16.1 million relating to changes in volumes as shown on line 5 of that page 2 and as broken out above in column 2.

c) If the Board was to affirm the DeBever degree day method, the remaining volume related deficiency of $ 16.1 million would decrease by the $ 21.2 million shown with Board Staff Interrogatory #17, resulting in a sufficiency of approximately $ 5 million.

Some of the other volume related impacts shown on lines 3 to 6 could change from the approximate impacts shown above but would only change marginally in total.

K4.2

Table 1

Comparison of Nine Different Degree Days Forecast Methodologies

Item		Col. 1 Energy Probe	Col. 2 de Bever	Col. 3 de Bever with Trend	Col. 4 10-Yr MA	Col. 5 20-Yr MA	Col. 6 30-Yr MA	Col. 7 Avg(20-Yr, 30-Yr MA)	Col. 8 Naïve	Col. 9 20-Yr Trend
1.1	Total operating costs incurred by EGDI in utilizing the method ('$000)	There are no material or significant operating costs incurred by using each of the degree day forecasting methods.								
1.2	Total Bill Impact on a Typical Residential Customer vs 20-Yr Trend (%)	1.5%	3.2%	0.2%	1.4%	3.3%	5.3%	2.6%	1.9%	0.0%
1.3	Delivery Bill Impact on a Typical Residential Customer vs 20-Yr Trend (%)	0.3%	0.6%	0.0%	0.3%	0.6%	0.9%	0.5%	0.3%	0.0%
1.4	Impact on Revenue Requirement vs 20-Yr Trend (%)	0.4%	0.7%	0.0%	0.3%	0.7%	1.1%	0.5%	0.4%	0.0%
1.5	Impact on Revenue Deficiency vs 20-Yr Trend ($M)	12.3	21.2	1.6	9.7	22.1	35.0	17.6	12.6	0.0
1.6	Volumetric Impact vs 20-Yr Trend ($10^6 m^3$)	192.1	331.7	25.0	151.8	345.6	548.2	275.0	196.5	0.0
1.7	Impact on Revenue Deficiency vs 2006 Board Approved Degree Days ($M)	-0.6	8.3	-11.3	-3.2	9.2	22.1	4.7	-0.3	-12.9

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.2
DATE February 1, 2007
08/99

K4.3

Exhibit N3.2
Vol. 3, para. 240

UNION GAS LIMITED

Undertaking of Mr. Fogwill
To Mr. Aiken

Please provide the actual equation filed with the coefficients, the various regression statistics, along with all the regression statistics: T Stats, F Value, Durban-Watson, R Squared.

The linear regression equations are attached for the trend methods only. There is no regression equation possible for the 30, 20 and 10 year averages because they are simple averages.

The performance statistics used for assessing the methods compared each methods' performance against actual over time and did not use the statistics for each individual equation. The performance tests that Union has used were the mean absolute percent error, mean percent error, root mean squared error and standard deviation.

Ontario Energy Board
FILE No. RP-2003-0063
UNDERTAKING N3.2
DATE Oct. 15/03
06/99

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K4.3
DATE February 1, 2007
06/99

Witness: Allan Fogwill
Question: October 8, 2003
Answer: October 15, 2003
Docket: RP-2003-0063

Source: ExC2/T4/S1/p9

Table 5

Actual and Forecast Toronto Degree Days

Year	Actual	DeBever	Difference	% Difference	20-Yr Trend	Difference	% Difference	Union	Difference	% Difference
1990	3,980	4,032	52	1%	4,003	23	1%	4,092	112	3%
1991	3,610	4,035	425	12%	3,973	363	10%	4,075	465	13%
1992	4,053	4,035	-18	0%	3,962	-91	-2%	4,069	16	0%
1993	4,168	3,947	-221	-5%	3,865	-303	-7%	4,014	-154	-4%
1994	4,331	3,998	-333	-8%	3,870	-461	-11%	4,018	-313	-7%
1995	3,785	4,046	261	7%	3,883	98	3%	4,023	238	6%
1996	4,266	4,132	-134	-3%	3,942	-324	-8%	4,057	-209	-5%
1997	4,063	4,082	19	0%	3,863	-200	-5%	4,008	-55	-1%
1998	3,389	4,142	753	22%	3,896	507	15%	4,025	636	19%
1999	3,475	4,129	654	19%	3,929	454	13%	4,038	563	16%
2000	3,616	3,977	361	10%	3,833	217	6%	3,974	358	10%
2001	3,782	3,859	77	2%	3,748	-34	-1%	3,920	138	4%
2002	3,337	3,759	422	13%	3,683	346	10%	3,874	537	16%
2003	4,102	3,737	-365	-9%	3,684	-418	-10%	3,865	-237	-6%
2004	3,785	3,570	-215	-6%	3,614	-171	-5%	3,815	30	1%
2005	3,772	3,806	34	1%	3,647	-125	-3%	3,831	59	2%
2006	N/A									
Average Error 1990-2005	**3,845**	**3,955**	**111**	**3%**	**3,837**	**-7**	**-0.2%**	**3,981**	**137**	**4%**
No. of Times Overforecasted			10			7			11	

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K4.4

DATE February 1, 2007

08/99

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K4.5

DATE February 1, 2007

08/99

EB-2006-0034
Exhibit K 4.5

Degree Day Methodologies - Comparison of Performance 1990 - 2005

Toronto Region

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Total Degree Days	61,513	62,016	63,524	65,069	66,001	63,698	63,285	62,096	62,580	61,395
Overforecast		8	11	12	12	11	10	6	6	7
Underforecast		8	5	4	4	5	6	10	10	9
Variance from Actual		503	2,011	3,556	4,488	2,185	1,772	583	1,067	-118
Percentage Variance		0.82%	3.27%	5.78%	7.30%	3.55%	2.88%	0.95%	1.73%	-0.19%

Eastern Region

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Total Degree Days	72,093	72,234	72,873	73,631	74,387	73,062	73,145	72,214	72,601	71,738
Overforecast		7	7	9	10	7	6	7	7	6
Underforecast		9	9	7	6	9	10	9	9	10
Variance from Actual		141	780	1,538	2,294	969	1,052	121	508	-355
Percentage Variance		0.20%	1.08%	2.13%	3.18%	1.34%	1.46%	0.17%	0.70%	-0.49%

Niagara Region

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Total Degree Days	57,102	57,191	57,888	58,644	58,911	57,884	58,547	58,038	58,987	56,856
Overforecast		8	8	10	12	8	10	10	11	7
Underforecast		8	8	6	4	8	6	6	5	9
Variance from Actual		89	786	1,542	1,809	782	1,445	936	1,885	-246
Percentage Variance		0.16%	1.38%	2.70%	3.17%	1.37%	2.53%	1.64%	3.30%	-0.43%

Averages

Item	*Actual*	*Naïve*	*10 YR MA*	*20 YR MA*	*30 YR MA*	*50/50*	*de Bever*	*de Bever/Tr*	*Energy Probe*	*20 YR Trend*
Average Degree Days	63,569	63,814	64,762	65,781	66,433	64,881	64,992	64,116	64,723	63,330
Avg. Overforecast		48%	54%	65%	71%	54%	54%	48%	50%	42%
Avg. Underforecast		52%	46%	35%	29%	46%	46%	52%	50%	58%
Average Variance		244	1,192	2,212	2,864	1,312	1,423	547	1,153	-240
Percentage Variance		0.38%	1.88%	3.48%	4.50%	2.06%	2.24%	0.86%	1.81%	-0.38%

Source: Toronto - I/16/20
Eastern and Niagara - I/5/8

Exhibit ________

EB-2006-0034

Cross-Examination Materials

On

Average Use & Degree Days

Energy Probe Research Foundation

January, 2007

Appendix 1

Mnemonics of the variables in the model are defined as follows:

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t) - LOG(X_{t-1})$
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
CRCE	Central Weather Zone Employment
ERCE	Eastern Weather Zone Employment
REAL_CRC_CPG	Real Commercial Gas Price for the Central Weather Zone
REAL_ERC_CPG	Real Commercial Gas Price for the Eastern Weather Zone
REAL_NRC_CPG	Real Natural Gas Price for the Niagara Weather Zone
OGDPFC	Ontario Real Gross Domestic Product
GOODS	Ontario Goods Producing Industry Real Domestic Product
TMAN	Ontario Manufacturing Industry Real Domestic Product
ORET92	Ontario Real Retail Sales
TIME	Time Trend
DUMPRE1991	Dummy Variable for Structural Break Prior to 1991
DUM00	Dummy Variable for 2000
DUM97	Dummy Variable for 1997
ECM_Region	Error Correction Term for Each Region

Appendix 2

Regression results are as follows:

Central Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic
C	0.894	1.884
LOG(CDD)	0.638	24.350
LOG(TIME)	-0.028	-5.084
LOG(CRCE)	0.296	6.082
LOG(REAL_CRC_CPG)	-0.029	-2.070
AR(1)	-0.537	-2.415
F Statistic	96.595	
Adjusted R-squared	0.962	
S.E. of regression	0.010	

Eastern Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic
C	3.932	8.947
LOG(EDD)	0.470	8.776
LOG(TIME)	-0.022	-4.903
LOG(REAL_ERC_CPG)	-0.037	-2.412
F Statistic	41.839	
Adjusted R-squared	0.860	
S.E. of regression	0.016	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.004	-0.969
DLOG(EDD)	0.468	11.951
ECM_ERC12(-1)	-1.217	-4.454
F Statistic	83.652	
Adjusted R-squared	0.897	
S.E. of regression	0.017	

Niagara Revenue Class 12 (Apartment)

Long Run Equation

Variable	Coefficient	t-Statistic
C	3.481	9.434
LOG(NDD)	0.496	10.725
LOG(TIME)	-0.009	-1.966
F Statistic	62.461	
Adjusted R-squared	0.860	
S.E. of regression	0.017	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.002	-0.420
DLOG(NDD)	0.468	14.467
ECM_NRC12(-1)	-0.883	-3.643
F Statistic	132.238	
Adjusted R-squared	0.932	
S.E. of regression	0.017	

Central Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-3.015	-2.939
LOG(CDD)	0.734	11.744
LOG(TIME)	-0.107	-5.814
LOG(OGDPFC)	0.316	5.279
DUMPRE1991	-0.074	-3.648
F Statistic	120.410	
Adjusted R-squared	0.960	
S.E. of regression	0.021	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.017	-2.443
DLOG(CDD)	0.822	34.461
DLOG(OGDPFC)	0.834	5.460
ECM_CRC48(-1)	-0.637	-3.283
DLOG(TIME)	-0.124	-3.946
AR(3)	-0.457	-2.023
F Statistic	238.613	
Adjusted R-squared	0.987	
S.E. of regression	0.011	

Eastern Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.752	-0.922
LOG(EDD)	0.734	11.492
LOG(TIME)	-0.147	-18.176
LOG(GOODS)	0.147	3.351
F Statistic	272.540	
Adjusted R-squared	0.976	
S.E. of regression	0.019	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.006	-1.357
DLOG(EDD)	0.745	22.908
DLOG(TIME)	-0.096	-3.399
DLOG(GOODS)	0.174	2.041
ECM_ERC48(-1)	-1.390	-4.700
AR(2)	-0.419	-1.652
F Statistic	104.883	
Adjusted R-squared	0.968	
S.E. of regression	0.014	

Niagara Revenue Class 48 (Commercial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-2.007	-1.507
LOG(NDD)	0.680	10.873
LOG(TIME)	-0.051	-4.390
LOG(ORET92)	0.298	3.006
LOG(REAL_NRC_CPG)	-0.123	-3.371
F Statistic	37.990	
Adjusted R-squared	0.881	
S.E. of regression	0.021	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.006	-1.507
DLOG(NDD)	0.639	17.253
DLOG(ORET92)	0.226	2.145
DLOG(REAL_NRC_CPG)	-0.034	-1.199
ECM_NRC48(-1)	-1.296	-5.254
F Statistic	139.704	
Adjusted R-squared	0.967	
S.E. of regression	0.016	

Central Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.506	-0.333
LOG(CDD)	0.570	6.012
LOG(TIME)	-0.094	-3.457
LOG(OGDPFC)	0.305	3.419
DUM00	0.077	2.338
DUMPRE1991	-0.072	-2.397
F Statistic	29.461	
Adjusted R-squared	0.877	
S.E. of regression	0.030	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.027	-3.309
DLOG(CDD)	0.662	14.384
DLOG(TIME)	-0.035	-1.115
DLOG(OGDPFC)	0.733	3.247
DUM00	0.070	3.042
ECM_CRC73(-1)	-0.965	-4.691
F Statistic	67.556	
Adjusted R-squared	0.946	
S.E. of regression	0.020	

Eastern Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-3.700	-1.340
LOG(EDD)	1.003	4.436
LOG(TIME)	-0.165	-2.808
LOG(ERCE)	0.673	1.963
DUMPRE1991	-0.227	-3.357
DUM00	0.268	3.734
F Statistic	36.588	
Adjusted R-squared	0.899	
S.E. of regression	0.067	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.035	-1.964
DLOG(EDD)	1.073	6.106
DUM00	0.318	3.947
ECM_ERC73(-1)	-0.940	-3.085
F Statistic	22.076	
Adjusted R-squared	0.769	
S.E. of regression	0.078	

Niagara Revenue Class 73 (Industrial)

Long Run Equation

Variable	Coefficient	t-Statistic
C	-8.461	-3.158
LOG(NDD)	0.550	3.308
LOG(TIME)	-0.206	-5.845
LOG(TMAN)	1.168	6.297
LOG(REAL_NRC_CPG)	-0.295	-3.229
DUM97	0.240	3.937
F Statistic	14.779	
Adjusted R-squared	0.775	
S.E. of regression	0.056	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.034	-2.318
DLOG(NDD)	0.737	6.183
DLOG(TMAN)	0.796	2.962
DLOG(REAL_NRC_CPG)	-0.203	-2.103
DUM97	0.290	4.905
ECM_NRC73(-1)	-0.743	-2.745
F Statistic	15.056	
Adjusted R-squared	0.787	
S.E. of regression	0.055	

TABLE 4

DRIVER VARIABLE ASSUMPTIONS

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	2002	2003	2004	2005	2006F	2007F	2008F
Central Heating Degree Days [1]	2,566	3,212	2,947	2,952	2,648	2,743	2,708
	-13.3%	25.2%	-8.2%	0.2%	-10.3%	3.6%	-1.3%
Eastern Heating Degree Days	3,108	3,857	3,612	3,599	3,249	3,405	3,384
	-13.4%	24.1%	-6.4%	-0.4%	-9.7%	4.8%	-0.6%
Niagara Heating Degree Days	2,423	3,079	2,810	2,858	2,558	2,735	2,718
	-15.3%	27.1%	-8.7%	1.7%	-10.5%	7.0%	-0.6%
Central Weather Zone Employment	1.8%	3.6%	2.6%	1.2%	2.8%	2.7%	2.5%
Eastern Weather Zone Employment	-0.2%	4.1%	-0.1%	1.3%	2.2%	2.1%	2.2%
Real Commercial Natural Gas Price	-24.2%	15.9%	2.6%	9.8%	15.2%	9.6%	9.4%
Ontario Real Retail Sales	3.4%	1.5%	0.4%	3.1%	1.7%	2.3%	2.5%
Ontario Real Gross Domestic Product	2.3%	2.1%	2.9%	2.4%	2.4%	2.5%	2.8%
Ontario Goods Producing Industry Real Domestic Product	1.3%	1.1%	3.2%	2.0%	2.9%	3.9%	4.4%
Ontario Manufacturing Industry Real Domestic Product	-0.2%	0.5%	4.1%	2.2%	3.3%	3.8%	4.4%

[1]Degree days are balance point meter reading heating degree days (adjusted for billing cycle). Heating degree days for fiscal year 2006 are calculated using actual heating degree days (October 2005 to March 2006) and Board Approved heating degree days (April 2006 to September 2006). Heating degree days for fiscal year 2007 are calculated using Board Approved degree days (October 2006 to December 2006) and the Company's heating degree day forecast (January 2007 to September 2007). Heating degree days for fiscal year 2008 are the Company's forecast heating degree days.

Summary Statistics

11. Table 5 shows the results that the models would generate for Rate 6 average use using actual 2005 data to allow parties to compare the results to the prior year's forecast. Note that Table 5 is not updated for 2004 since a 2004 Board Approved normalized average use forecast is not available. In order to compare the variance between normalized actual and Board Approved average use on the same basis, the actual results for each year have to be normalized to the corresponding Board Approved degree days for that year. The 2005 actual average use has been normalized to the 2005 Board Approved degree days for that year, 3747. The Board Approved normalized average use per customer, Column 3, are the forecasts filed in RP-2003-0203. The model's normalized average use per customer, Column 6, was generated using all actual data up to and including Fiscal 2005 data. The five years results show that the model's forecast of historical average use does

Appendix 1

Mnemonics of the variables in the model are defined as follows:

Mnemonic	Definition
C	Constant Term
LOG(X)	Logarithm of Variable X
DLOG(X)	$LOG(X_t) - LOG(X_{t-1})$
CDD, EDD, NDD	Balance Point Heating Degree Days for Central, Eastern and Niagara Weather Zones
MET20_VINT	Vintage Variable for the Metro Region, Central Weather Zone
WES20_VINT	Vintage Variable for the Western Region, Central Weather Zone
CEN20_VINT	Vintage Variable for the Central Region, Central Weather Zone
NOR20_VINT	Vintage Variable for the Northern Region, Central Weather Zone
ERC20_VINT	Vintage Variable for the Eastern Weather Zone
NRC20_VINT	Vintage Variable for the Niagara Weather Zone
REAL_CRC_RPG	Real Residential Natural Gas Price for the Central Weather Zone
REAL_ERC_RPG	Real Residential Natural Gas Price for the Eastern Weather Zone
REAL_NRC_RPG	Real Residential Natural Gas Price for the Niagara Weather Zone
TIME	Time Trend
CRCE	Central Weather Zone Employment
ECM_Region	Error Correction Term for Each Region

Appendix 2

Regression results are as follows:

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.548	-2.059
LOG(CDD)	0.713	20.638
LOG(REAL_CRC_RPG)	-0.091	-3.707
LOG(MET20_VINT)	0.223	1.807
LOG(TIME)	-0.021	-2.293
F Statistic	276.582	
Adjusted R-squared	0.982	
S.E. of regression	0.011	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.005	-2.451
DLOG(CDD)	0.748	31.838
DLOG(REAL_CRC_RPG)	-0.097	-4.740
ECM_MET20(-1)	-0.551	-2.132
F Statistic	419.043	
Adjusted R-squared	0.985	
S.E. of regression	0.010	

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-1.300	-2.108
LOG(CDD)	0.711	22.730
LOG(REAL_CRC_RPG)	-0.115	-8.296
LOG(WES20_VINT)	0.177	4.526
LOG(CRCE)	0.083	1.245
F Statistic	316.337	
Adjusted R-squared	0.984	
S.E. of regression	0.011	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.004	-1.773
DLOG(CDD)	0.726	32.110
DLOG(REAL_CRC_RPG)	-0.119	-5.939
ECM_WES20(-1)	-0.701	-2.742
F Statistic	392.831	
Adjusted R-squared	0.984	
S.E. of regression	0.010	

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-2.764	-3.168
LOG(CDD)	0.709	16.413
LOG(REAL_CRC_RPG)	-0.111	-3.249
LOG(CEN20_VINT)	0.251	5.671
LOG(CRCE)	0.266	2.792
LOG(TIME)	-0.017	-1.233
F Statistic	179.047	
Adjusted R-squared	0.978	
S.E. of regression	0.014	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.001	-0.199
DLOG(CDD)	0.707	23.123
DLOG(REAL_CRC_RPG)	-0.084	-2.814
DLOG(CEN20_VINT)	0.155	1.177
ECM_CEN20(-1)	-1.156	-4.322
F Statistic	173.929	
Adjusted R-squared	0.973	
S.E. of regression	0.013	

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-2.170	-3.358
LOG(CDD)	0.728	21.514
LOG(REAL_CRC_RPG)	-0.109	-7.291
LOG(NOR20_VINT)	0.241	8.195
LOG(CRCE)	0.186	2.628
F Statistic	405.577	
Adjusted R-squared	0.988	
S.E. of regression	0.011	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.001	-0.116
DLOG(CDD)	0.724	28.898
DLOG(REAL_CRC_RPG)	-0.113	-4.314
DLOG(NOR20_VINT)	0.143	1.469
ECM_NOR20(-1)	-1.071	-4.156
F Statistic	238.417	
Adjusted R-squared	0.980	
S.E. of regression	0.011	

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-1.533	-4.343
LOG(EDD)	0.801	17.726
LOG(REAL_ERC_RPG)	-0.123	-4.993
LOG(ERC20_VINT)	0.114	2.946
LOG(TIME)	-0.024	-2.486
F Statistic	247.257	
Adjusted R-squared	0.980	
S.E. of regression	0.012	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.008	-2.593
DLOG(EDD)	0.821	25.144
DLOG(REAL_ERC_RPG)	-0.126	-4.547
ECM_ERC20(-1)	-1.069	-3.904
F Statistic	224.601	
Adjusted R-squared	0.972	
S.E. of regression	0.013	

Niagara Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic
C	-0.317	-0.798
LOG(NDD)	0.668	13.040
LOG(REAL_NRC_RPG)	-0.104	-2.707
LOG(TIME)	-0.034	-2.334
LOG(NRC20_VINT)	0.334	1.758
F Statistic	125.634	
Adjusted R-squared	0.961	
S.E. of regression	0.018	

Short Run Equation

Variable	Coefficient	t-Statistic
C	-0.009	-2.592
DLOG(NDD)	0.624	18.439
DLOG(REAL_NRC_RPG)	-0.042	-1.314
ECM_NRC20(-1)	-1.043	-3.947
F Statistic	169.678	
Adjusted R-squared	0.964	
S.E. of regression	0.016	

the weather impact has been taken out. Using the estimated coefficients, weather normalized average use data are obtained by replacing actual degree days in the model with budgeted degree days for fiscal 2007.

Data – Driver Variables

13. Driver variable assumptions are presented in Table 2 in year over year growth rates. Major driver variables in the model are balance point heating degree days adjusted for billing cycles, vintage, time trend, real energy prices, and economic variables. The driver variable assumptions are based on economic assumptions from the *Economic Outlook, Winter 2006* which can be found at Exhibit C1, Tab 1, Schedule 1.

TABLE 2

DRIVER VARIABLE ASSUMPTIONS

Col 1.	Col 2.	Col 3.	Col 4.	Col 5.	Col 6.	Col 7.	Col 8.
Fiscal Year	2002	2003	2004	2005	2006F	2007F	2008F
Central Heating Degree Days [1]	2,566	3,212	2,947	2,952	2,648	2,743	2,708
	-13.3%	25.2%	-8.2%	0.2%	-10.3%	3.6%	-1.3%
Eastern Heating Degree Days	3,108	3,857	3,612	3,599	3,249	3,405	3,384
	-13.4%	24.1%	-6.4%	-0.4%	-9.7%	4.8%	-0.6%
Niagara Heating Degree Days	2,423	3,079	2,810	2,858	2,558	2,735	2,718
	-15.3%	27.1%	-8.7%	1.7%	-10.5%	7.0%	-0.6%
Real Residential Natural Gas Price	-21.2%	15.0%	2.1%	8.5%	13.4%	8.5%	8.5%
Central Weather Zone Employment	1.8%	3.6%	2.6%	1.2%	2.8%	2.7%	2.5%
Vintage: Metro Region, Central Wether Zone	-1.1%	-1.4%	-1.1%	-0.9%	-0.9%	-0.9%	-0.9%
Vintage: Western Region, Central Weather Zone	-4.3%	-4.6%	-3.9%	-3.4%	-3.3%	-3.2%	-3.1%
Vintage: Central Region, Central Weather Zone	-3.3%	-4.1%	-4.0%	-3.6%	-3.6%	-3.5%	-3.4%
Vintage: Northern Region, Central Weather Zone	-5.4%	-5.0%	-4.8%	-3.6%	-3.4%	-3.2%	-3.0%
Vintage: Eastern Weather Zone	-3.4%	-3.6%	-3.7%	-3.1%	-3.0%	-2.9%	-2.8%
Vintage: Niagara Weather Zone	-1.2%	-1.4%	-1.5%	-1.4%	-1.4%	-1.4%	-1.4%

[1]Degree days are balance point meter reading heating degree days (adjusted for billing cycle). Heating degree days for fiscal year 2006 are calculated using actual heating degree days (October 2005 to March 2006) and Board Approved heating degree days (April 2006 to September 2006). Heating degree days for fiscal year 2007 are calculated using Board Approved degree days (October 2006 to December 2006) and the Company's heating degree day forecast (January 2007 to September 2007). Heating degree days for fiscal year 2008 are the Company's forecast heating degree days.

ECONOMIC OUTLOOK WINTER 2006

CANADA & U.S.

CALENDAR YEAR[1]	2002	2003	2004	2005	2006F	2007F
REAL GDP (% CHANGE)						
CANADA	3.1	2.0	2.9	2.8	3.0	3.1
U.S.	1.6	2.7	4.2	3.6	3.5	3.0
REAL CONSUMPTION (% CHANGE)	3.7	3.1	3.4	3.9	3.0	2.9
REAL INVESTMENT (% CHANGE)						
BUSINESS	0.7	6.2	6.9	7.0	5.1	3.8
NON-RESIDENTIAL CONSTRUCTION	-7.3	5.7	0.8	7.0	6.8	4.0
MACHINERY & EQUIPMENT	-3.3	6.4	9.8	10.4	8.6	6.3
RESIDENTIAL CONSTRUCTION	14.3	6.2	8.3	3.6	0.2	0.8
REAL EXPORTS (% CHANGE)	1.0	-2.1	5.0	2.7	3.1	3.6
REAL IMPORTS (% CHANGE)	1.5	4.1	8.1	7.1	3.6	3.3
HOUSING STARTS (000's)	205	218	233	223	192	185
UNEMPLOYMENT RATE (%)	7.7	7.6	7.2	6.7	6.7	6.9
EMPLOYMENT GROWTH (% CHANGE)	2.4	2.3	1.8	1.4	1.7	1.7
CONSUMER PRICES (% CHANGE)						
CANADA	2.2	2.8	1.8	2.4	2.5	2.0
U.S.	1.6	2.3	2.7	3.3	3.0	2.6

[1] Throughout this exhibit ‘Fiscal’ refers to the year ending September 30, while ‘Calendar’ refers to the year ending December 31.

ONTARIO

CALENDAR YEAR	2002	2003	2004	2005	2006F	2007F
REAL GDP (% CHANGE)	3.0	1.8	3.0	2.6	2.3	2.5
GOODS	3.0	0.6	3.4	2.0	2.9	4.3
MANUFACTURING	2.6	0.1	4.4	2.1	3.2	4.2
SERVICE	2.9	2.3	2.8	3.0	2.7	3.0
REAL CONSUMPTION (% CHANGE)	3.9	3.2	3.3	3.3	2.7	3.1
HOUSING STARTS (000's)	83.6	85.2	85.1	78.8	70.9	75.7
UNEMPLOYMENT RATE (%)	7.1	6.9	6.8	6.6	6.4	6.7
EMPLOYMENT GROWTH (% CHANGE)	1.9	2.9	1.7	1.3	1.6	1.9
CONSUMER PRICES (% CHANGE)	2.0	2.7	1.9	2.2	2.3	2.0
REAL RETAIL SALES (% CHANGE)	3.7	0.7	1.3	2.8	1.6	2.5
WAGE RATE (% CHANGE)	1.2	0.9	1.4	3.0	3.6	2.7

REGIONS

CALENDAR YEAR	2002	2003	2004	2005	2006F	2007F
GTA						
HOUSING STARTS (000's)	46.2	48.1	44.7	43.0	39.3	38.8
SINGLES	25.0	22.3	21.5	17.7	16.9	17.5
MULTIPLES	21.2	25.8	23.2	25.4	22.4	21.2
CONSUMER PRICES (% CHANGE)	2.1	3.0	1.7	1.8	2.1	1.9
UNEMPLOYMENT RATE (%)	7.1	7.1	6.8	6.8	6.7	6.7
EMPLOYMENT GROWTH (% CHANGE)	2.1	3.4	2.3	1.8	2.6	2.6
EASTERN						
HOUSING STARTS (000's)	8.0	7.1	7.5	5.2	5.7	6.2
SINGLES	3.9	3.7	3.5	2.5	2.7	3.0
MULTIPLES	4.1	3.4	4.0	2.6	3.0	3.1
CONSUMER PRICES (% CHANGE)	2.1	2.5	1.9	2.3	2.3	2.0
UNEMPLOYMENT RATE (%)	7.3	6.9	6.6	6.7	6.6	6.5
EMPLOYMENT GROWTH (% CHANGE)	0.3	3.9	-0.7	1.7	2.2	2.4
NIAGARA						
HOUSING STARTS (000's)	1.4	1.8	2.0	1.5	1.4	1.5
SINGLES	1.1	1.3	1.5	1.1	1.0	1.1
MULTIPLES	0.3	0.5	0.6	0.4	0.4	0.4
UNEMPLOYMENT RATE (%)	7.3	7.0	7.3	7.0	6.6	6.6
EMPLOYMENT GROWTH (% CHANGE)	1.1	1.8	-2.5	3.1	0.8	1.2

CANADA & U.S.

FISCAL YEAR	2002	2003	2004	2005	2006F	2007F	2008F
REAL GDP (% CHANGE)							
CANADA	2.5	2.5	2.5	3.0	2.8	3.2	3.0
U.S.	1.2	2.2	4.3	3.7	3.6	3.1	3.2
REAL CONSUMPTION (% CHANGE)	3.2	3.4	3.1	4.0	3.0	3.0	2.9
REAL INVESTMENT (% CHANGE)							
BUSINESS	0.0	4.8	7.7	6.7	5.7	4.0	2.6
NON-RESIDENTIAL CONSTRUCTION	-4.4	1.5	3.2	4.4	7.7	4.9	0.0
MACHINERY & EQUIPMENT	-6.6	5.0	10.1	10.4	9.0	6.7	5.8
RESIDENTIAL CONSTRUCTION	14.6	7.2	8.5	4.7	1.0	0.4	1.2
REAL EXPORTS (% CHANGE)	-0.8	-1.7	4.2	2.4	3.4	3.4	3.9
REAL IMPORTS (% CHANGE)	-2.2	4.3	7.5	7.9	4.2	3.2	3.4
HOUSING STARTS (000's)	195	215	230	229	199	186	181
UNEMPLOYMENT RATE (%)	7.7	7.6	7.3	6.9	6.6	6.9	6.9
EMPLOYMENT GROWTH (% CHANGE)	1.7	2.7	1.9	1.4	1.6	1.7	1.5
CONSUMER PRICES (% CHANGE)							
CANADA	1.6	3.3	1.7	2.2	2.6	2.1	2.0
U.S.	1.5	2.4	2.3	3.3	3.3	2.6	2.6

ONTARIO

FISCAL YEAR	2002	2003	2004	2005	2006F	2007F	2008F
REAL GDP (% CHANGE)	2.3	2.1	2.9	2.4	2.4	2.5	2.8
GOODS	1.3	1.1	3.2	2.0	2.9	3.9	4.4
MANUFACTURING	-0.2	0.5	4.1	2.2	3.3	3.8	4.4
SERVICE	2.8	2.5	2.8	2.7	2.8	3.0	3.0
REAL CONSUMPTION (% CHANGE)	3.3	4.0	2.5	3.8	2.5	3.1	3.1
HOUSING STARTS (000's)	81.5	84.0	85.9	80.8	71.3	75.0	77.8
UNEMPLOYMENT RATE (%)	7.1	7.0	6.8	6.7	6.4	6.6	6.8
EMPLOYMENT GROWTH (% CHANGE)	1.2	3.3	1.8	1.3	1.5	2.0	1.8
CONSUMER PRICES (% CHANGE)	1.7	2.9	1.9	2.2	2.2	2.2	2.0
REAL RETAIL SALES (% CHANGE)	3.4	1.5	0.4	3.1	1.7	2.3	2.5
WAGE RATE (% CHANGE)	1.3	1.0	1.3	2.0	4.5	2.5	2.7

REGIONS

FISCAL YEAR	2002	2003	2004	2005	2006F	2007F	2008F
GTA							
HOUSING STARTS (000's)	46.3	47.0	46.2	43.7	38.8	39.6	38.7
SINGLES	24.4	22.9	22.3	18.3	16.6	17.8	17.6
MULTIPLES	21.9	24.1	23.9	25.4	22.2	21.9	21.1
CONSUMER PRICES (% CHANGE)	1.8	3.2	1.9	1.7	2.0	2.1	1.8
UNEMPLOYMENT RATE (%)	6.9	7.1	6.8	7.0	6.7	6.7	6.7
EMPLOYMENT GROWTH (% CHANGE)	1.8	3.6	2.6	1.2	2.8	2.7	2.5
EASTERN							
HOUSING STARTS (000's)	7.4	6.7	7.9	5.7	5.6	6.0	6.6
SINGLES	3.7	3.1	4.1	2.7	2.6	2.9	3.3
MULTIPLES	3.7	3.5	3.8	3.0	3.0	3.1	3.3
CONSUMER PRICES (% CHANGE)	1.7	2.8	1.9	2.2	2.2	2.2	2.0
UNEMPLOYMENT RATE (%)	7.2	6.9	6.9	6.7	6.5	6.5	6.5
EMPLOYMENT GROWTH (% CHANGE)	-0.2	4.1	-0.1	1.3	2.2	2.1	2.2
NIAGARA							
HOUSING STARTS (000's)	1.3	1.7	2.1	1.5	1.4	1.5	1.6
SINGLES	1.1	1.3	1.4	1.2	1.0	1.1	1.2
MULTIPLES	0.2	0.5	0.7	0.3	0.4	0.4	0.4
UNEMPLOYMENT RATE (%)	6.9	7.1	7.5	6.8	6.6	6.6	6.6
EMPLOYMENT GROWTH (% CHANGE)	-0.1	2.2	-2.3	3.6	-0.4	1.8	0.9

GAS VOLUME BUDGET

1. The purpose of this evidence is to present the 2007 Test Year volume budget and request the Board's approval of the volumes as summarized in Table 1. The information shown in this evidence is on a calendar-year basis (i.e., on a December 31 year end) excluding the Historical Actual vs. Board Approved section. The Test Year Budget includes calendar 2005 actual consumption information up to and including December 2005.

2. A summary of the volumes, customers, and revenues is provided below in Table 1. Further detail is provided at Exhibit C3, Tab 2, Schedule 1; Exhibit C4, Tab 2, Schedule 1; Exhibit C4, Tab 2, Schedule 5; and Exhibit C5, Tab 2, Schedule 1.

Table 1
Summary of Gas Sales and Transportation
Volumes, Customers and Revenues
(Volumes in 10^6m^3)

	Calendar 2005 Actual	Calendar 2006 Board Approved Budget	Calendar 2006 Bridge Year Estimate	Calendar 2007 Budget
General Service Volumes	8 019.5	7 932.8	7 758.6	7 625.8
Contract Volumes	4 190.3	4 387.9	4 116.5	4 131.7
Total Volumes, Gas Sales and Transportation	12 209.8	12 320.7	11 875.1	11 757.5
Customers, Gas Sales and Transportation (Average)	1 735 907	1 792 615	1 780 459	1 823 258
Revenues, Gas Sales and Transportation ($ Millions)	3 064.4	3 091.3	3 348.8	3 072.3

Witnesses: I. Chan
T. Ladanyi

3. This evidence has divided into the following sections:
    - Comparison of 2007 Budget and 2006 Estimate
    - Evaluation of Forecast Accuracy – Historical Normalized Actual vs. Board Approved Budget
    - Demand Forecast Methodology
    - Comparison of 2006 Estimate and 2005 Actual
    - Comparison of 2006 Estimate and 2006 Board Approved
    - Weather Normalization Methodology

Comparison of 2007 Budget and 2006 Estimate

4. The 2007 volume budget reflects the meter reading heating degree day forecast of 3,617, a decrease of 128 degree days compared to the 2006 Bridge Year Estimate of 3,745. Meter reading heating degree days are acquired by amalgamating Gas Supply heating degree days with the billing schedules. Evidence related to the forecast of Gas Supply heating degree days is presented at Exhibit C2, Tab 4, Schedule 1. The test year degree day forecast has been developed using the proposed 20 Year Trend methodology as it produces the best fit in the Company's analysis and comprehensive review of competing degree day forecasting methods.

5. The 2007 volumes budget of 11 757.5 10^6m^3 are 117.6 10^6m^3 or 1.0% below the 2006 Bridge Year Estimate of 11 875.1 10^6m^3. On a weather-normalized basis, the 2007 Budget volumes are forecast to be 90.3 10^6m^3 or 0.8% above the 2006 Bridge Year Estimate. The increase on a normalized basis is made up of an increase in general service volumes of 44.7 10^6m^3 and an increase in the contract market of

45.6 10^6m^3. Further rate class detail and explanation are provided at Exhibit C3, Tab 2, Schedule 3.

6. The increase in the general service volumes of 44.7 10^6m^3 on a weather-normalized basis is primarily due to customer growth of 140.3 10^6m^3 and incremental added load initiatives of 3.6 10^6m^3 as described in the Opportunity Development evidence at Exhibit D1, Tab 8, Schedule 1. These additional volumes mitigate the lower average use per customer of 99.0 10^6m^3 as a result of the Company's initiatives, customers' own conservation initiatives and high natural gas prices.[1] Further explanations are provided in the average use section on the next page. Further numerical details are provided at Exhibit C3, Tab 2, Schedule 3.

7. The increase of 45.6 10^6m^3 in the contract market on a weather-normalized basis is primarily due the addition of two large customers in 2007, the incremental load of an existing customer, and the full operational capacity of several new large customers added in 2006 and existing customers; partially offset by a loss in load due to two industrial plant closures in the Food and Beverage sector and the loss of theToronto Transit Commission ("TTC") as a customer due to its discontinued use of Natural Gas Vehicles ("NGV") for buses starting in 2006. Further details are provided at Exhibit C3, Tab 2, Schedule 3. Overall, the 2007 budget represents the forecast that integrates all of the actual experiences and the best known information about contract customers at the time the budget was developed.

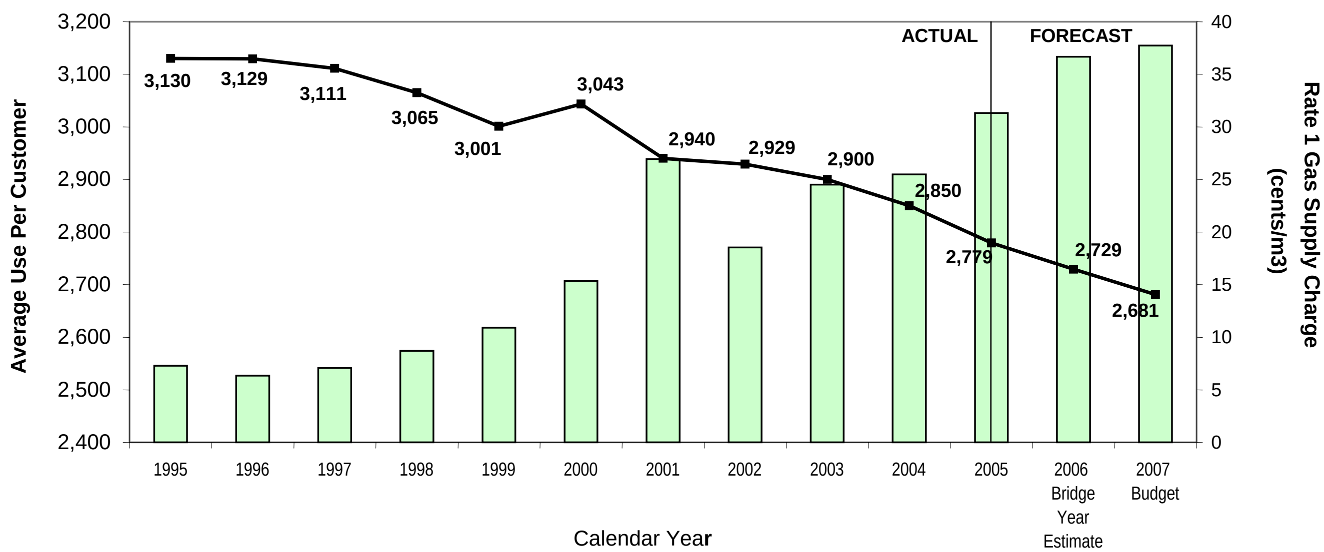
<u>General Service Average Use: 2007 Budget</u>

8. From 1995 to 2005, normalized residential average use has declined by an average of 35.0 m^3 or 1.2% per year. However, during the volatile and high natural gas price

[1] Real Residential Natural Gas Price – Table 2- Exhibit C2, Tab 3, Schedule 1.

period between 2001 and 2005, normalized residential average use has decreased by an average of 53 m³ or 1.8% per year. Figure 1 shows the residential average use from 1995 to the 2007 Test Year on a test year weather normalized basis, as filed at Exhibit C5, Tab 2, Schedule 3.

Figure 1
Residential Normalized Average Use (m^3)

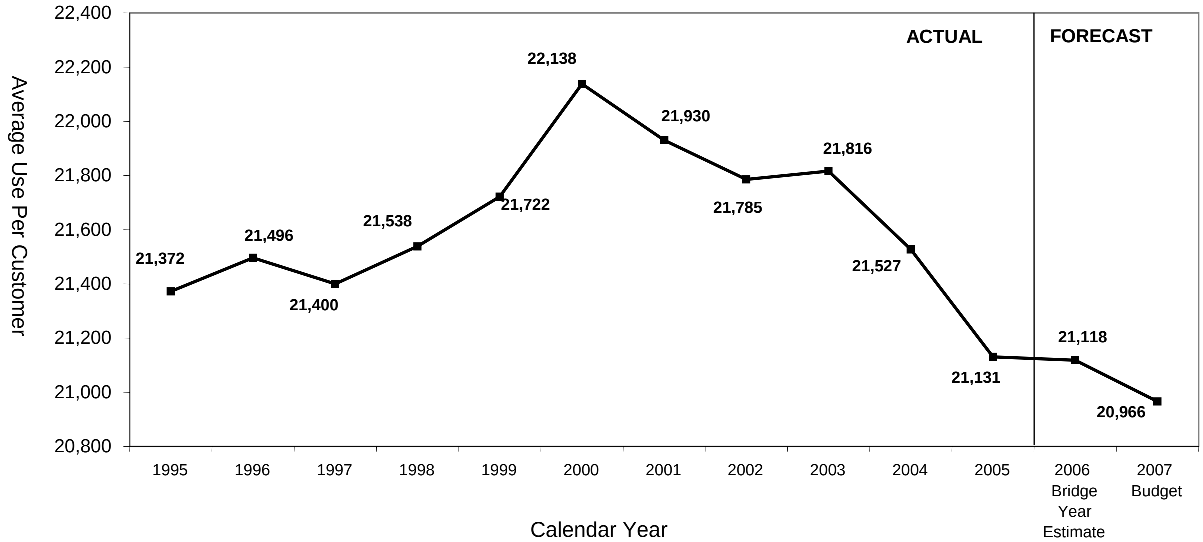


9. Similarly, from 1995 to 2005, normalized Rate 6 average use has decreased by an average of 24.0 m^3 or 0.11% per year. During the period between 2001 and 2005, normalized Rate 6 average use has decreased by an average of 201 m^3 or 0.9% per year. Figure 2 on the next page shows the Rate 6 average use from 1995 to the 2007 Test Year on a test year weather normalized basis, as filed at Exhibit C5, Tab 2, Schedule 3. Rate 6 is comprised of the apartment, commercial, and industrial sectors.

Witnesses: I. Chan
T. Ladanyi

Figure 2

Rate 6 Normalized Average Use (m^3)



10. Tables 3 to 6 have been developed in response to previous years' interrogatories by quantifying the impact of the average use's driver variables on the system-wide average use forecast by sector.

11. Compared with the 2006 Bridge Year Estimate, residential average uses is expected to continue to decline in 2007. This decline is due to the expectation of higher gas prices in 2007 than in 2006 based on experience in recent years, the Company's DSM initiatives, new homes with improved thermal envelopes and higher efficiencies on new heating and water heating equipment, and other conservation iniatives; partially offset by the Company's added load initiatives and the penetration of new gas appliances as a result of moderate employment growth in 2007. Other conservation captures the historical reduction in volumes due to the impact of conservation activities on average uses; such as the ongoing gas equipment efficiency effect as a result of the replacement of old equipment with

medium or high efficiency furnaces, increased energy efficiency of new gas-fired water heaters effective September 1, 2004, continued home renovation efforts in older building, and conservation initiatives originated by customers themselves or as a result of government programs.

12. Residential average uses are significantly affected by gas prices. Customers respond to a sharp price increase in various ways, such as lowering thermostat controls and adding additional layers of clothing, purchasing more efficient gas furnaces, appliances and/or programmable thermostats, or by renovating their homes to make them more energy efficient. Together with increasing gas prices in 2006 which were higher than the increase that occurred in 2001, forecasts of higher real natural gas prices in 2007 will continue to drive a decrease in the average use in 2007 at a similar trend as experienced in the 2001 to 2005 actuals.

13. Apartment sector average uses is expected to decrease in 2007, primarily due to the Company's DSM initiatives, conservation initiatives originated by customers or a result of government programs, and higher gas prices in 2007; partially offset by moderate employment growth.

14. Commercial sector average uses are expected to continue to decrease in 2007, primarily due to Company's DSM initiatives, other conservation, and higher gas prices in 2007; partially offset by still moderate employment growth and the Company's Utility Growth Plan initiatives. Other conservation captures the historical reduction in volumes due to the impact of conservation activities on average uses; such as continued conservation efforts in older buildings, improved thermal envelopes for newer buildings, higher efficiencies of new heating and water heating

equipment, and self-imposed conservation activities either initiated by customers or as a result of government programs.

15. Industrial sector average uses are expected to increase in 2007, primarily due to moderate economic growth and customer migration from contract rates to general service rates; partially offset by the Company's Utility Growth Plan initiatives, higher gas prices in 2007, and other conservation. Other conservation captures the reduction in volumes due to the impact of conservation activities on average uses; such as a change in production process, improved thermal envelopes for newer buildings, higher efficiencies on new heating and water heating equipments, and self-imposed conservation activities either initiated by the customers or as a result of government programs.

16. Trends in this sector have been variable over time. Economic conditions and rate switching have also played a significant role in recent years' industrial average uses as this sector is affected by the restructuring of large contract customers, fluctuations in product demand and changes in production process. In 2005 and 2006, there were a number of industrial customers that switched from contract rates to general service rates who are not expected to switch back in 2007 as a result of their consumption not meeting the minimum threshold requirement of 340,000 m^3 for contract customers. There are a variety of reasons that the customers may not meet the minimum threshold, such as customers embracing DSM or conservation initiatives, winding down industrial plants, changes in production process to enhance efficiency, and plant consolidation.

Table 3

Factors Influencing the Changes in Residential Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate ($10^6 m^3$)

Factors	Total Volume ($10^6 m^3$)	
DSM Initiatives	(11.8)	
New Homes (a)	(6.4)	
Other Conservation (b)	(14.9)	
Gas Prices	(48.6)	
Gas Appliances (c)	0.0	*
Growth Initiatives or Added Load (d)	3.4	
Total	(78.3)	

(a) Measured by vintage variable as explained at Exhibit C2, Tab 3, Schedule 1, reflecting the historical impacts of improved building envelopes for new homes along with more efficient new space heating furnaces and water heaters on average uses.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces for the existing homes, new more energy efficient gas-fired storage water heaters effective September 1, 2004, and conservation initiatives originated by customers or as a result of by government programs, such as programmable thermostats, low-flow showerheads, and home renovations..

(c) Measured by employment variable to reflect the demand for Gas Appliances or Gas Technologies.

(d) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Table 4

Factors Influencing the Changes in Apartment Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate (10^6 m^3)

Factors	Total Volume ($10^6 m^3$)	
DSM Initiatives	(2.7)	
Economics, Gas Appliances (a)	1.4	
Other Conservation (b)	0.0	*
Gas Prices	(2.5)	
Growth Initiatives or Added Load (c)	0.0	
Total	(3.8)	

(a) Measured by economic variables as explained at Exhibit C2, Tab 3, Schedule 2, to reflect the demand for Gas Appliances or Gas Technologies, to capture the historical actual average trend of the apartment's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, and construction trend.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces, and conservation initiatives originated by customers or as a result of government programs, such as programmable thermostats, improved building envelopes, low-flow showerheads, and building renovations.

(c) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

* Less than 50,000 m^3

Witnesses: I. Chan
T. Ladanyi

Table 5

Factors Influencing the Changes in Commercial Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate ($10^6 m^3$)

Factors	Total Volume ($10^6 m^3$)
DSM Initiatives	(11.7)
Economics, Gas Appliances (a)	4.8
Other Conservation (b)	(6.4)
Gas Prices	(0.6)
Growth Initiatives or Added Load (c)	0.2
Total	(13.7)

(a) Economics variables are used to measure the demand for Gas Appliances or Gas Technologies, to capture the historical actual average trend of the commercial's sector average use, such as transfer gains/losses impact on average uses, vacancy rate, and construction trend.

(b) Other Conservation includes the expected ongoing technology improvements of furnaces, and conservation initiatives originated by customers or as a result of government programs, such as programmable thermostats, improved building envelopes, office space requirements, and building renovations.

(c) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

Table 6

Factors Influencing the Changes in Industrial Gas Consumption

Between 2007 Test Year Budget and 2006 Bridge Year Estimate ($10^6 m^3$)

Factors	Total Volume ($10^6 m^3$)
DSM Initiatives	(1.4)
Economics, Gas Appliances (a)	2.7
Other Conservation (b)	(0.6)
Gas Prices	(0.3)
Growth Initiatives or Added Load (c)	0.0
Total	0.4

(a) Economics variables are used to measure the demand for Gas Appliances or Gas Technologies, to capture the historical actual average trend of the industrial sector average use, such as transfer gains/losses impact on average uses, vacancy rate, and construction trend.

(b) Other Conservation includes the technology improvements of furnaces, and self-imposed conservation activities, such as change in process, programmable thermostats, improved building envelopes, and building renovations.

(c) Added Load is based on the Company's Utility Growth Plan initiatives developed by the Opportunity Development group. See Exhibit D1, Tab 8, Schedule 1, for detailed information about these added load programs.

BOARD STAFF INTERROGATORY #17

INTERROGATORY

Ref: C2/T4/S1

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) If one assumes increasing weather volatility is an important factor to consider in forecasting degree days, does the data contained in C2/T4/S1/page12/table8 "Out-of-sample Forecast Performance, Recent Five Year Period (2001 to 2005)" support a conclusion that the "Energy Probe" method is the most appropriate method to forecast degree days?

b) For each of "20-yr Trend", "Energy Probe", "de Bever" and "de Bever with Trend" degree days forecast methodologies , please complete the table below:

	20-yr Trend	Energy Probe	de Bever	de Bever with Trend
Total operating costs incurred by EGDI in utilizing the method				
Total bill impact on a typical residential customer (%)				
Impact on revenue requirement (%)				

RESPONSE

a) Increasing weather volatility is an important factor to consider in forecasting degree days. It should be noted that for the periods examined by the Company in Exhibit C2, Tab 4, Schedule 1, page 4, Table 3, the ten-year period from 1996 to 2005 was the most volatile period for Central Area degree days. During the 1996 to 2005 period the standard deviation of Central Area degree days was 313.5. While the Company has not examined the volatility of degree days over a 5 year period it should be noted that the 20-Year Trend method, as per Exhibit C2, Tab 4, Schedule 1, page 11, Table 7 ranks best over the 1996 to 2005 period which coincides to the most volatile period for Central Area degree days.

Witnesses: I. Chan
J. Collier
K. Culbert
J. Denomy
T. Ladanyi

b) The Company has received a number of interrogatories requesting production of numerous different degree-day scenarios in different formats. Due to the amount of effort required, the Company has consolidated these different degree-day scenarios into one response.

It should be noted that the volumetric changes associated with changing the Company's test year budget degree days of 3,617 to the requested levels reviewed herein, could lead to other adjustments to be undertaken in the gas supply, transportation, and storage operating departments. Curtailment volumes, commodity purchases, unaccounted for gas, storage levels, and transportation (utilization) would all be impacted. As a result, the Company is reluctant to provide this "short-cut" response without expressing concern regarding risks of such potentially significant consequences. Furthermore, as shown in Exhibit C2, Tab 4, Schedule 1, the proposed 20-year trend methodology maintains superior performance relative to other alternatives rendering such "short-cut" responses moot.

With the understanding that a "short-cut" response is an approximation inclusive of the assumption that the volume increases would be the sole driver of a requirement/sufficiency/deficiency change, the Company provides the following calculations.

Table 1 on the next page illustrates the requested operating costs incurred (Item 1.1), percent of both total bill (Item 1.2) and delivery charge (Item 1.3) impact on a typical annualized total customer bill impact, both percent (Item 1.4) and level impact (Item 1.5) on revenue requirement, and volumetric impact (Item 1.6) under each of the reviewed degree days forecasting methodology shown at Exhibit C2, Tab 4, Schedule 1, page 12, Table 8 compared to the proposed "20-Year Trend" method for 2007.

Since the Company cannot influence the commodity portion of the total bill, the percent of delivery charge impact (Item 1.3) provides a better representation of the true rate impact on residential customers that is controllable by the Company than the total bill impact (Item 1.2). This is also consistent with the Board's Minimum Filing Requirements in a manner to try to isolate the delivery related sufficiency/deficiency separate and apart from the commodity related sufficiency/deficiency. As each transportation-service customer can incur different commodity rate charged by his or her broker or supplier, the Company's gas supply charge is used as a proxy for these customers. The bill is calculated based upon July 2006 rates under EB-2006-0099.

Witnesses: I. Chan
J. Collier
K. Culbert
J. Denomy
T. Ladanyi

All the impacts reported here include the corresponding forecast degree days for the Central, Eastern, and Niagara regions based upon the degree days forecasting methodology under review.

Table 1
Comparison of Eight Different Degree Days Forecast Methodologies

Item		Col. 1 Energy Probe	Col. 2 de Bever	Col. 3 de Bever with Trend	Col. 4 10-Yr MA	Col. 5 20-Yr MA	Col. 6 30-Yr MA	Col. 7 Avg(20-Yr, 30-Yr MA)	Col. 8 Naïve
1.1	Total operating costs incurred by EGDI in utilizing the method ('$000)	There are no material or significant operating costs incurred by using each of the degree day forecasting methods.							
1.2	Total Bill Impact on a Typical Residential Customer (%)	1.5%	3.2%	0.2%	1.4%	3.3%	5.3%	2.6%	1.9%
1.3	Delivery Bill Impact on a Typical Residential Customer (%)	0.3%	0.6%	0.0%	0.3%	0.6%	0.9%	0.5%	0.3%
1.4	Impact on Revenue Requirement (%)	0.4%	0.7%	0.0%	0.3%	0.7%	1.1%	0.5%	0.4%
1.5	Impact on Revenue Deficiency ($M)	12.3	21.2	1.6	9.7	22.1	35.0	17.6	12.6
1.6	Volumetric Impact vs 20-Yr (10^6m^3)	192.1	331.7	25.0	151.8	345.6	548.2	275.0	196.5

Witnesses: I. Chan
J. Collier
K. Culbert
J. Denomy
T. Ladanyi

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: C2/T4/S1, para. 27

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) Please provide Tables 5, 6, 7 and 8 for the Eastern region.
b) Please provide Tables 5, 6, 7 and 8 for the Niagara region.

RESPONSE

a) Please see tables below for the Eastern region.

Table 5 Eastern
Actual and forecast Eastern degree days ('out-of-sample'), 1990 to 2005

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Fiscal Year	Actual	Naïve	10-yr MA	20-yr MA	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	20-yr Trend
1990	4,663	4,564	4,579	4,671	4,691	4,581	4,618	4,479	4,466	4,471
1991	4,258	4,647	4,570	4,667	4,684	4,578	4,642	4,538	4,521	4,472
1992	4,827	4,663	4,584	4,654	4,688	4,597	4,628	4,577	4,606	4,505
1993	4,730	4,258	4,534	4,625	4,675	4,560	4,544	4,479	4,474	4,446
1994	4,971	4,827	4,536	4,625	4,683	4,599	4,637	4,547	4,576	4,515
1995	4,293	4,730	4,579	4,630	4,673	4,606	4,662	4,589	4,622	4,539
1996	4,779	4,971	4,604	4,643	4,687	4,655	4,723	4,635	4,730	4,623
1997	4,665	4,293	4,586	4,633	4,669	4,598	4,659	4,551	4,569	4,528
1998	4,101	4,779	4,606	4,636	4,671	4,621	4,686	4,562	4,503	4,571
1999	4,089	4,665	4,640	4,627	4,666	4,634	4,666	4,604	4,572	4,602
2000	4,301	4,101	4,593	4,586	4,645	4,587	4,560	4,509	4,358	4,529
2001	4,500	4,089	4,537	4,554	4,624	4,533	4,469	4,518	4,437	4,442
2002	4,025	4,301	4,501	4,543	4,603	4,494	4,417	4,450	4,341	4,384
2003	4,821	4,500	4,525	4,530	4,592	4,497	4,456	4,444	4,539	4,403
2004	4,579	4,025	4,445	4,491	4,565	4,448	4,290	4,328	4,565	4,331
2005	4,491	4,821	4,454	4,516	4,571	4,474	4,488	4,404	4,722	4,377

Witness: J. Denomy

Table 6 Eastern
Out-of-sample forecast performance, all available years (1990 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.9%	9	8.9%	9	0.6%	2	44%	1	298	9	30	***8***
10-yr MA	5.9%	6	7.1%	5	1.5%	5	44%	1	54	2	19	***3***
20-yr MA	5.6%	2	7.2%	6	2.6%	8	56%	1	57	3	20	***5***
20-yr Trend	**6.2%**	**8**	**6.9%**	**3**	**0.1%**	**1**	**38%**	**7**	**83**	**6**	**25**	***6***
30-yr MA	5.7%	3	7.6%	8	3.6%	9	63%	7	44	1	28	***7***
50/50	5.7%	4	7.0%	4	1.8%	6	44%	1	60	4	19	***3***
de Bever	5.8%	5	7.4%	7	1.9%	7	38%	7	119	8	34	***9***
de Bever with Trend	6.0%	7	6.9%	2	0.6%	3	44%	1	80	5	18	***2***
Energy Probe	**5.2%**	**1**	**6.1%**	**1**	**1.1%**	**4**	**44%**	**1**	**109**	**7**	**14**	***1***

Table 7 Eastern
Out-of-sample forecast performance, recent ten year period (1996 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.9%	9	9.7%	9	0.8%	1	50%	1	341	9	29	***7***
10-yr MA	6.0%	6	7.6%	5	3.0%	6	50%	1	67	3	21	***4***
20-yr MA	5.9%	3	7.8%	6	3.6%	8	60%	6	56	2	25	***6***
20-yr Trend	**6.2%**	**8**	**7.3%**	**2**	**1.4%**	**2**	**40%**	**6**	**104**	**6**	**24**	***5***
30-yr MA	6.2%	7	8.4%	8	4.8%	9	70%	9	45	1	34	***9***
50/50	5.9%	2	7.6%	4	3.1%	7	50%	1	74	4	18	***3***
de Bever	6.0%	4	8.0%	7	2.8%	5	40%	6	141	8	30	***8***
de Bever with Trend	6.0%	5	7.3%	3	1.9%	3	50%	1	94	5	17	***2***
Energy Probe	**4.7%**	**1**	**6.1%**	**1**	**2.5%**	**4**	**50%**	**1**	**132**	**7**	**14**	***1***

Table 8 Eastern
Out-of-sample forecast performance, recent five year period (2001 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.4%	9	8.7%	9	2.7%	8	40%	1	324	9	36	***9***
10-yr MA	4.5%	3	6.1%	2	0.6%	2	40%	1	41	5	13	***2***
20-yr MA	4.5%	4	6.4%	7	1.3%	6	60%	1	25	2	20	***4***
20-yr Trend	**5.4%**	**8**	**6.2%**	**4**	**1.8%**	**7**	**20%**	**8**	**40**	**4**	**31**	***8***
30-yr MA	4.8%	5	6.9%	8	2.8%	9	60%	1	24	1	24	***6***
50/50	4.5%	2	6.1%	3	0.5%	1	40%	1	31	3	10	***1***
de Bever	4.9%	6	6.2%	5	1.0%	4	20%	8	79	7	30	***7***
de Bever with Trend	5.2%	7	6.4%	6	0.8%	3	40%	1	70	6	23	***5***
Energy Probe	**4.1%**	**1**	**5.0%**	**1**	**1.1%**	**5**	**40%**	**1**	**143**	**8**	**16**	***3***

b) Please see tables below for the Niagara region.

Table 5 Niagara
Actual and forecast Niagara degree days ('out-of-sample'), 1990 to 2005

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Fiscal Year	Actual	Naïve	10-yr MA	20-yr MA	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	20-yr Trend
1990	3,603	3,649	3,690	3,708	3,707	3,689	3,643	3,712	3,745	3,670
1991	3,288	3,663	3,670	3,708	3,703	3,677	3,651	3,700	3,840	3,652
1992	3,676	3,603	3,664	3,699	3,700	3,670	3,651	3,684	3,794	3,640
1993	3,840	3,288	3,609	3,680	3,687	3,617	3,609	3,545	3,569	3,548
1994	4,000	3,676	3,577	3,679	3,689	3,620	3,641	3,573	3,587	3,550
1995	3,472	3,840	3,623	3,692	3,689	3,630	3,686	3,647	3,702	3,571
1996	3,930	4,000	3,635	3,708	3,706	3,670	3,709	3,722	3,883	3,634
1997	3,615	3,472	3,630	3,701	3,697	3,634	3,693	3,674	3,736	3,572
1998	3,174	3,930	3,659	3,722	3,704	3,649	3,709	3,695	3,698	3,594
1999	3,270	3,615	3,673	3,702	3,699	3,655	3,703	3,690	3,624	3,612
2000	3,377	3,174	3,626	3,658	3,680	3,613	3,698	3,643	3,503	3,545
2001	3,595	3,270	3,587	3,628	3,668	3,578	3,714	3,633	3,552	3,487
2002	3,122	3,377	3,564	3,614	3,654	3,546	3,663	3,576	3,505	3,438
2003	3,917	3,595	3,595	3,602	3,652	3,558	3,642	3,572	3,730	3,463
2004	3,605	3,122	3,539	3,558	3,632	3,523	3,510	3,454	3,709	3,414
2005	3,618	3,917	3,547	3,585	3,644	3,555	3,625	3,518	3,810	3,466

Table 6 Niagara
Out-of-sample forecast performance, all available years (1990 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.8%	9	10.4%	9	0.7%	2	50%	1	272	9	30	***6***
10-yr MA	6.5%	2	8.2%	3	2.0%	4	50%	1	47	2	12	***1***
20-yr MA	6.8%	5	8.6%	5	3.3%	7	63%	5	51	3	25	***4***
20-yr Trend	**6.7%**	**3**	**7.8%**	**1**	**0.1%**	**1**	**44%**	**4**	**80**	**7**	**16**	***3***
30-yr MA	6.8%	4	8.6%	6	3.7%	8	75%	9	24	1	28	***5***
50/50	6.4%	1	8.0%	2	1.9%	3	50%	1	52	5	12	***1***
de Bever	7.0%	7	8.8%	8	3.1%	6	63%	5	52	4	30	***6***
de Bever with Trend	7.2%	8	8.7%	7	2.2%	5	63%	5	79	6	31	***8***
Energy Probe	**6.9%**	**6**	**8.4%**	**4**	**3.8%**	**9**	**69%**	**8**	**118**	**8**	**35**	***9***

Table 7 Niagara
Out-of-sample forecast performance, recent ten year period (1996 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.3%	9	10.9%	9	1.2%	2	50%	1	321	9	30	***7***
10-yr MA	6.9%	3	8.8%	4	3.0%	4	50%	1	46	2	14	***2***
20-yr MA	7.4%	5	9.5%	6	4.2%	6	60%	4	58	4	25	***4***
20-yr Trend	**7.2%**	**4**	**8.1%**	**2**	**0.6%**	**1**	**40%**	**4**	**78**	**6**	**17**	***3***
30-yr MA	7.4%	6	9.5%	7	4.9%	9	80%	9	27	1	32	***8***
50/50	6.8%	2	8.6%	3	2.8%	3	50%	1	53	3	12	***1***
de Bever	7.8%	8	9.8%	8	4.7%	7	70%	7	63	5	35	***9***
de Bever with Trend	7.5%	7	9.2%	5	3.3%	5	60%	4	86	7	28	***6***
Energy Probe	**6.2%**	**1**	**7.9%**	**1**	**4.8%**	**8**	**70%**	**7**	**128**	**8**	**25**	***4***

Table 8 Niagara
Out-of-sample forecast performance, recent five year period (2001 to 2005)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.4%	9	9.6%	9	2.8%	8	40%	1	310	9	36	***9***
10-yr MA	5.3%	1	7.4%	2	0.4%	3	20%	6	24	3	15	***1***
20-yr MA	5.4%	3	8.0%	6	1.3%	4	40%	1	27	4	18	***3***
20-yr Trend	**6.8%**	**8**	**7.6%**	**4**	**2.8%**	**7**	**20%**	**6**	**28**	**5**	**30**	***8***
30-yr MA	5.5%	5	8.3%	7	2.7%	6	80%	6	13	1	25	***6***
50/50	5.5%	4	7.4%	3	0.0%	1	20%	6	20	2	16	***2***
de Bever	6.1%	6	8.6%	8	2.2%	5	60%	1	75	7	27	***7***
de Bever with Trend	6.3%	7	7.9%	5	0.0%	2	40%	1	68	6	21	***4***
Energy Probe	**5.3%**	**2**	**6.5%**	**1**	**2.9%**	**9**	**60%**	**1**	**128**	**8**	**21**	***4***

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ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Ref: C2/T4/S1, Table 9

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) Please provide a table similar to Table 9 for the Eastern region Environment Canada degree day forecasts.
b) Please provide a table similar to Table 9 for the Niagara region Environment Canada degree day forecasts.

RESPONSE

a) Please see Table 1 below.

Table 1

Eastern region Environment Canada degree day forecasts, 2007-8

Col. 1	*Col. 2*	*Col. 3*
Forecast Method	2007	2008
Naïve	4,491	4,491
10-yr MA	4,435	4,435
20-yr MA	4,510	4,510
30-yr MA	4,567	4,567
50% 20-yr Trend / 50% 30-yr MA	4,487	4,483
de Bever	4,558	4,558
de Bever with Trend	4,370	4,357
Energy Probe	4,459	4,445
20-Year Trend	**4,408**	**4,399**

Witness: J. Denomy

b) Please see Table 2 below.

Table 2

Niagara region Environment Canada degree day forecasts, 2007-8

Col. 1	*Col. 2*	*Col. 3*
Forecast Method	2007	2008
Naïve	3,618	3,618
10-yr MA	3,522	3,522
20-yr MA	3,576	3,576
30-yr MA	3,641	3,641
50% 20-yr Trend / 50% 30-yr MA	3,577	3,575
de Bever	3,643	3,643
de Bever with Trend	3,511	3,504
Energy Probe	3,597	3,589
20-Year Trend	**3,513**	**3,508**

ENERGY PROBE INTERROGATORY #11

INTERROGATORY

Ref: C2/T4/S1, para. 39

Issue Number: 2.3
Issue: Is the change in forecasting methodology for degree days from the “de Bever” to the “20-Year Trend” justified?

Please provide a description of what each of the following statistics mean:

a) the Adjusted R-squared figure of 0.08591;
b) the Prob. figure of 0.1124 in column 5 on the TREND line;
c) the F-statistic value of 2.785709; and
d) what is the significant of a negative value for an adjusted R-squared figure?

RESPONSE

The following response assumes that a constant coefficient is included in all regression models discussed.

a) R-squared measures the percentage of the total variation in the dependent variable, in this case heating degree days, explained by a regression model. The formula for calculating R-squared is a nondecreasing function of the number of independent variables in a regression model. In other words, R-squared will increase or at least never decrease as more independent variables are added to the regression model.

   Adjusted R-squared takes this property of R-squared into account and adjusts R-squared for the number of independent variables, in other words the degrees of freedom, in a regression model. Consequently, if the number of estimated coefficients in a regression model is greater than 1, adjusted R-squared will be less than R-squared.

   Adjusted R-squared therefore explains the percentage of variation in the dependent variable explained by the regression model after adjusting for the number of independent variables in the regression model. Since adjusted R-squared takes into account degrees of freedom it is possible to have a negative adjusted R-squared statistic.

Witness: J. Denomy

b) The Prob. figure is known as the p-value or probability value of a coefficient. The p-value is the observed or exact level of significance for a coefficient. It is defined as the lowest significance level at which a null hypothesis can be rejected. If the p-value is less than a chosen level of significance, the null hypothesis is rejected in favour of the alternative hypothesis.

c) The F-statistic is used to test whether or not all of the independent variables in a regression model jointly explain variation in the dependent variable. In the case of a simple linear regression (that is a regression with only one independent variable) the results of an F-test will be the same as the result of a t-test under the null hypothesis that the coefficient of the independent variable is zero.

d) Please see response to part a).

It should be noted that while high R-squared values, high t-statistics (low p-values) and high F-statistics (low p-values) are desirable, these tests are in no way indicative of the forecasting ability of a model. Consider the following example.

The table below shows two of the models used to generate the forecast of Fiscal 2006 Degree Days for the Central weather zone presented in the response to Energy Probe Interrogatory #6 at Exhibit I, Tab 5, Schedule 6. The first model is the 20-Year Trend model, the second model is the Energy Probe model.

Table 1

20-Year Trend Model

Dependent Variable: ECCEN
Sample: 1985 2004
Included observations: 20

Col. 1	***Col. 2***	***Col. 3***	***Col. 4***	***Col. 5***
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4780.95	552.24	8.66	0.0000
TIME	-17.19	10.46	-1.64	0.1176

R-squared	0.1305	F-statistic	2.7013
Adjusted R-squared	0.0822	Prob(F-statistic)	0.1176
Durbin-Watson stat	1.8681		

Witness: J. Denomy

Table 2

Energy Probe Model

Dependent Variable: ECCEN
Sample: 1964 2004
Included observations: 41

Col. 1	***Col. 2***	***Col. 3***	***Col. 4***	***Col. 5***
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4715.59	1145.28	4.12	0.0002
TIME	-13.64	4.15	-3.29	0.0022
WACDD	1.60	0.85	1.89	0.0669
ACDD	-1.62	0.89	-1.82	0.0762

R-squared	0.4633	F-statistic	10.6475
Adjusted R-squared	0.4198	Prob(F-statistic)	0.0000
Durbin-Watson stat	1.8945		

From the tables presented above it is apparent that the Energy Probe Model has higher R-squared statistics, higher t-statistics and a higher F-statistic than the 20-Year Trendmodel. However, the 20-Year trend model is a far better predictor of degree days. Actual Degree Days for Fiscal 2006 were 3,481. The Energy Probe model predicts Fiscal 2006 Degree Days to be 3,857 which translates into a percentage variance of 10.80%. The 20-Year Trend model predicts Fiscal 2006 Degree Days to be 3,681 which translates into a percentage variance of 5.75%.

ENERGY PROBE INTERROGATORY #12

INTERROGATORY

Ref: C2/T4/S1, Tables 13-15

Issue Number: 2.3
Issue: Is the forecast of degree days appropriate?

a) Does the Company agree with the following statement: 'When using regression analysis in forecasting applications it is generally acceptable to exclude variables with coefficients that have t-statistics less than one in absolute value.' If not, why not?
b) The TREND values in the equations found in Figures A1 and A2 have t-statistics that are less than 1.0. Please explain why the Company has left the TREND variable in the equations.
c) Please re-estimate both equations (Eastern and Niagara) excluding the TREND variable.
d) What is the forecast of Environment Canada degree days for the Eastern and Niagara regions for 2007 and 2008 using these re-estimated equations?
e) What is the forecast of gas supply degree days for the Eastern and Niagara regions for 2007 and 2008 based on the forecasts in part (d) above?

RESPONSE

Based on the questions in this interrogatory the responses below assumes Energy Probe is referring to Figures A2 and A3.

a) The Company agrees with the statement that it is generally *acceptable* to exclude variables with coefficients that have t-statistics less than one in absolute value.

b) The Company has left the TREND variable in the equations in order to produce forecasts of degree days using the 20-Year Trend method. Like the application of the de Bever method the Company intends to utilize whichever degree day forecasting methodology that is adopted for the Central weather zone for the Eastern and Niagara weather zones.

c) If the TREND variable is excluded from the equations the 20-Year Trend method defaults to the 20 Year Moving Average Method. Forecasts of Environment Canada

Witness: J. Denomy

degree days for the Eastern and Niagara regions based on the 20 Year Moving Average method can be found in the response to Energy Probe Interrogatory #9 at Exhibit I, Tab 5, Schedule 9.

d) Please see response to c).

e) Please see table below for the Eastern and Niagara region gas supply degree day forecasts based on the 20 Year Moving Average method.

Table 1

Gas Supply Degree Days

Col. 1	*Col. 2*	*Col. 3*
	Gas Supply	
Fiscal Year	Eastern	Niagara
2007	4,465	3,545
2008	4,465	3,545

Witness: J. Denomy

17. In summary, the de Bever with Trend method consistently provides the most accurate and symmetrical results, and despite having less stability than other methods, still ranks the best overall. Therefore the Company is proposing to use the de Bever with Trend methodology for determining future degree days.

18. Table 5 provides the Central Zone Environment Canada degree day forecast for Fiscal Years 2005 to 2007 considering each of the various tested methodologies. The de Bever with Trend methodology produces a forecast of 3,715 degree days for Fiscal 2006.

TABLE 5 CENTRAL EC DEGREE DAY FORECAST COMPARISON

Forecast Method	FY 2005	FY 2006	FY 2007
DeBever	3,806	3,842	3,842
de Bever with Trend	**3,712**	**3,715**	**3,700**
50% 20-yr Trend / 50% 30-yr MA	3,831	3,841	3,831
10-yr MA	3,814	3,760	3,763
20-yr MA	3,908	3,879	3,876
30-yr MA	4,014	4,000	3,998
Naïve	4,102	3,785	3,785
EGD Forecast*	**3,743**	**3,722**	**3,706**

* The Company proposes to drop the 5-year weighted average variable if it is found to be not significant in the formulation of the de Bever with Trend methodology.

19. As noted in Table 5 above, the Company is proposing that should the 5-year weighted average variable be found to be not significant in the formulation of the de Bever with Trend forecast, that that variable not be included in the final estimate. For the Fiscal 2006 forecast, the 5-year weighted average variable was found to be not statistically significant (T-Statistic 0.47), and was therefore dropped from the equation. The Company will incorporate this variable in future specifications when it is found to be statistically significant. The Company believes that the 5-year weighted-average term is extremely important in capturing short-term weather trends, as it was originally intended to do, and that the model is only improved with the use of a trend variable.

20. The estimated de Bever with Trend equation, the adjusted R-squared, the Durbin-Watson statistic, and the F-statistic for the Fiscal 2006 forecast are as follows:

- Heating Degree days = 4574.287 - 15.784 Trend
  (t-statistics) (44.37) (-5.22)

  R^2Ad = 0.41
  DW = 1.87
  F-Stat = 27.28
  Sample = 1964 to 2004

21. Tables 6 to 8 below present actual degree day history by weather zone along with the de Bever with Trend model's fitted values by fiscal year. Figures 4 to 6 that follow the tables present this information graphically.

ENERGY PROBE INTERROGATORY #27

INTERROGATORY

Reference: Ex. A2, Tab 2, Sch. 5, Page 13 & 15 & 16

a) Please provide the same regression statistics as provided for the equation found on page 13 for the equations found in Note 2 on both page 15 and 16.

b) Please provide the same regression statistics as provided for the equation on page 13 for the equations found in Note 2 on both page 15 and 16, where both equations have been modified to included the five year weighted average as an explanatory variable.

RESPONSE

a) The regression statistics for the Eastern and Niagara de Bever with Trend models, excluding the 5-year weighted average variable, are provided below (note that the trend variable begins in 1953).

Eastern Region:

- Heating Degree days = 4957.528 – 10.407(Trend)
  (t-statistics) (49.48) (-3.58)

  R^2Ad = 0.23
  DW = 2.10
  F-Stat = 12.83
  Sample = 1965 to 2004

Niagara Region:

- Heating Degree days = 3943.985 - 8.376(Trend)
  (t-statistics) (34.42) (-2.58)

  R^2Ad = 0.13
  DW = 2.00
  F-Stat = 6.64
  Sample = 1967 to 2004

b) The regression statistics for the Eastern and Niagara de Bever with Trend models, including the 5-year weighted average variable are provided below (note that the trend variable begins in 1953).

Eastern Region:

- Heating Degree days = 6105.53 – 12.719(Trend) - 0.231(5-yr WA)
  (t-statistics) (3.64) (-2.85) (-0.69)

  R^2Ad = 0.22
  DW = 2.15
  F-Stat = 6.56
  Sample = 1965 to 2004

Niagara Region:

- Heating Degree days = 5128.171 – 10.917(Trend) - 0.299(5-yr WA)
  (t-statistics) (3.80) (-2.51) (-0.88)

  R^2Ad = 0.13
  DW = 2.06
  F-Stat = 3.69
  Sample = 1967 to 2004

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Appendix

39. The equation and test statistics that correspond to the Fiscal 2007 forecast for the 20-Year Trend method are presented in Figures A1 to A3.[7]

Figure A1
20-Year Trend forecasting equation and test statistics, Central

Dependent Variable: ECCEN   Method: Least Squares
Sample: 1986 2005   Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	4802.0	562.1	8.543	0
TREND	-17.434	10.446	-1.669	0.1124

Adjusted R-squared	0.08591	F-statistic	2.785709
Durbin-Watson stat	1.86762		

[7] The mnemonics in Figures A1 through A6 are as follows:

CEN	Central region
EAS	Eastern region
NIA	Niagara region
TREND	Trend (1943=1 for Central, 1941=1 for Eastern and Niagara)
EC*XXX*	Environment Canada degree days, where *XXX* is CEN, EAS or NIA
WA*XXX*	Five-year weighted average of degree days, where *XXX* is CEN, EAS or NIA
AVG*XXX*	Five-year average of degree days, where *XXX* is CEN, EAS or NIA

Figure A2
20-Year Trend forecasting equation and test statistics, Eastern

Dependent Variable: ECEAS   Method: Least Squares
Sample: 1986 2005   Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5004.7	586.7	8.531	0
TREND	-8.904	10.514	-0.847	0.4082

Adjusted R-squared	-0.015105	F-statistic	0.717279
Durbin-Watson stat	2.051416		

Figure A3
20-Year Trend forecasting equation and test statistics, Niagara

Dependent Variable: ECNIA   Method: Least Squares
Sample: 1986 2005   Included observations: 20

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	3879.6	537.2	7.222	0
TREND	-5.469	9.627	-0.568	0.577

Adjusted R-squared	-0.036963	F-statistic	0.322728
Durbin-Watson stat	1.958124		

40. Figures A4 through A6 are analogous to Figures A1 through A3, but correspond to the Energy Probe method. Note the cycle lengths of 41, 40 and 40 for the Central, Eastern and Niagara weather zones respectively, as indicated by the number of included observations.

Figure A4
Energy Probe forecasting equation and test statistics, Central

Dependent Variable: ECCEN   Method: Least Squares
Sample: 1965 2005   Included observations: 41

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5403.2	1190.7	4.538	0.0001
TREND	-17.171	4.427	-3.878	0.0004
WACEN	1.363	0.776	1.757	0.0871
AVGCEN	-1.509	0.794	-1.900	0.0652

Adjusted R-squared	0.469415	F-statistic	12.79616
Durbin-Watson stat	1.942138		

Figure A5
Energy Probe forecasting equation and test statistics, Eastern

Dependent Variable: ECEAS   Method: Least Squares
Sample: 1966 2005   Included observations: 40

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	7959.7	1693.7	4.700	0
TREND	-14.701	4.241	-3.466	0.0014
WAEAS	1.912	0.801	2.388	0.0223
AVGEAS	-2.489	0.857	-2.903	0.0063

Adjusted R-squared	0.338958	F-statistic	7.665912
Durbin-Watson stat	2.301955		

Figure A6
Energy Probe forecasting equation and test statistics, Niagara

Dependent Variable: ECNIA — Method: Least Squares
Sample: 1966 2005 — Included observations: 40

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
C	5760.0	1216.5	4.735	0
TREND	-8.040	3.208	-2.506	0.0169
WANIA	1.916	0.757	2.532	0.0159
AVGNIA	-2.389	0.824	-2.901	0.0063

Adjusted R-squared	0.216996	F-statistic	4.602723
Durbin-Watson stat	2.055237		

RP-2003-0063
EB-2003-0087
EB-2003-0097

IN THE MATTER OF.the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, Schedule B;

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage, and transmission of gas for the period commencing January 1, 2004.

BEFORE: Paul B. Sommerville
Presiding Member

Art Birchenough
Member

DECISION WITH REASONS

March 18, 2004

The Board notes the concerns expressed about the inherent complexity of programs of this kind, but is not convinced Union's proposed changes add materially to the program's complexity. The changes proposed by RMI and accepted by Union are unlikely to diminish the capacity of the current program and offer the opportunity for marginal improvements. To the extent that intervenors have significant concerns about the operation of Union's risk management program, it is open to them in future proceedings to bring expert evidence recommending appropriate changes to the program.

The Board notes that LPMA and VECC supported the risk management program, but argued that there was a need for increased reporting requirements. This position was characterized by Union as leading to unnecessary and inappropriate micro-management. The Board believes that Union's commitment to file an updated risk management policy, and at the time of deferral account disposition to provide all relevant data for an assessment of the cost impacts and compliance with the policy is sufficient to deal with these concerns.

The Board finds that Union's risk management program does provide value to ratepayers and is, therefore, appropriate, and that the specific changes Union is proposing to implement in the 2004 rate year are reasonable and provide an opportunity to enhance the value of the program.

2.2 WEATHER NORMALIZATION

Union's Request

Union proposes to change its weather normalization methodology and to recover the cost consequences in its rates. This proposal was supported by written evidence produced for Union by Weather Bank Inc (WB) and by Dr. Andrew Weaver, a professor of climatology at the University of Victoria.

Background

Normal weather is defined in terms of heating degree days (“HDD”), calculated on the variances in daily temperatures below 18° C. For example, if the mean daily temperature is 11°C, there are 18 - 11 = 7 HDDs on that day. If the mean daily temperature is 18° C or higher, there are no HDDs.

Weather normalization is used in forecasting demand for the general service classes (M2, R1 and R10), storage and transportation allocations, gas supply planning, and rate design. Weather normalization is also used to estimate average use per customer, which, when multiplied by the forecast number of customers, yields a demand forecast. Although weather normalization is not used directly to forecast demand for other classes, it can have impacts on other rate classes by affecting load balancing costs.

Union has historically used a 30-year rolling average method. In the RP-2002-0130 proceeding respecting 2003 rates, Union proposed to introduce a twenty-year trend methodology similar to what it was already using for distribution system planning and its gas supply portfolio. The impact of extending its use to ratemaking would have been to increase the revenue requirement to be captured in 2003 rates by an extra $13.7 million. At the time, Union was under a three-year trial PBR plan and sought to make this change as a non-routine adjustment. The PBR plan had been established on the basis of the existing weather normalization methodology. The Board denied Union's application on the basis that the weather risk was to be managed by Union as part of its PBR plan, and it was not appropriate to effect a change of this magnitude in the course of the PBR period.

Union’s Position

Union’s evidence states that, based on data from 1985 to 2000, the 30-year average weather normalization methodology consistently overestimates the heating demand by customers by about 7.6%. Mr. Fogwill of Union testified that the impact of a 1% variance in HDDs is about $3.0 million in annual delivery revenues.

Union argued that the 30-year average method assumed a static long run climatic condition and that this assumption was invalid. It noted that over the last 17 years, the method over-forecast HDDs fourteen times, and under-forecast HDDs only three times. Union cited Dr. Weaver's evidence in respect of climate change and global warming in support of its contention that variations were no longer symmetrical around the weather normal estimate.

In addition, Union stated that "... the yearly variability in temperature is increasing, with the standard deviation of 166 HDDs over the period 1956-1985 period increasing to 310 HDDs over the period 1972-2001. Union stated that its consultant, WB, agreed with Dr. Weaver that global warming was occurring. WB also supported Union's claim that volatility was increasing, noting an increase in the frequency of weather events such as El Nino and La Nina.

Dr. Weaver stated that there was an increase in global average temperature of approximately 0.6 degrees Centigrade (+/- 2°) over the twentieth century. He stated the warming trend occurred during two periods, 1901-1945 and 1976-2000 and were separated by a cooling period between 1945-1976. Union stated that 0.6 degrees per century corresponded to 1.6 HDDs per year. Dr. Weaver gave an estimate of a global average temperature increase of 2°C, but qualified this figure as it applies to Ontario, due to the amplification effect of Ontario geography.

Mr. Root of WB testified that in his experience extreme weather events had become much more common over the last 20 years. He suggested that use of the 20-year trend method would have the effect of mitigating the volatility associated with such extreme weather.

Union listed five objectives that its proposed normalization method was assessed against:

1. symmetry – actual HDDs are expected to vary positively and negatively equally with respect to the forecast HDDs;

2. accuracy – over time the variance between actual and normal HDDs should be minimized;

3. stability – the year over year normalized HDD estimate should not vary significantly when measured using standard deviation;

4. sustainability – the method should not require significant amendments in the near future; and

5. simplicity – the method should be easy to use.

The 20 year trend methodology uses data from twelve Environment Canada weather stations in Union's franchise area. The data is weighted by the throughput volumes in the region associated with each weather station. Union then applied ordinary least squares regression analysis to find the best fit to the weighted HDD.

Union ranked seven weather normalization methods by weighting and applying the above five objectives. The weightings applied by Union were on a scale from 1 to 3 as follows:

1. symmetry was given a weight of 3,
2. accuracy was given a weight of 2, and
3. stability, sustainability, and simplicity were given a weight of 1.

Based on these measures, Union ranked the methods in order, from best to worst, as follows: 20-year trend with forecast information, 20-year trend, 30-year trend, 38-year trend, 20-year average, 10-year average, and 30-year average. Union proposed the 20-year trend method rather than the 20-year trend with forecast information method, arguing that the latter was far more complex and that it relied upon a third party's proprietary model and therefore might not be sustainable.

Union stated that the rate impact of adopting the new method would be an increase of $20.4 million in the revenue requirement which would be allocated to the M2, R01, and R10 general service classes only. These impacts resulted from an approximately 3.9% deviation between the 30-year weather average and the proposed 20-year trend weather normalization methodologies. Union proposed to allocate the revenue impacts only to the general service classes because these are the only classes for which Union forecasts demand using weather normalization.

Union's witness testified that other than EGDI, whose weather normalization methodology includes a trending component and a moving average component, no other Canadian utility uses a trend method for this purpose. Further, Union was unable to cite any U.S. gas utility that uses a 20-year trend method.

Union noted that Environment Canada, the U.S. Weather Service, and the World Meteorological Organization all used a 30-year average weather normalization methodology. Dr. Weaver was unaware of any national or international meteorological organization that has changed from a 30-year average to a 20-year trend method, but he pointed out that those groups use the methodology to define a reference value and not as an indicator of the rate at which the reference is changing.

Although Union agreed that the data in evidence showed increasing variability over time, i.e., the data may exhibit heteroscedasticity, Union stated that it had not statistically tested for heteroscedasticity. Union also stated that the data it was relying on was time series data whose mean and variance were changing over time. The data were non-stationary and the validity of standard statistical tests was in question if the data were not stationary.

Board Findings

The Board is asked to approve a change in the weather normalization methodology that is applied to M2, R1 and R10 customer class forecast volumes. Union proposes to apply the 20 year trend methodology currently used to allocate upstream transportation and storage to unbundled customers.

The five objectives and associated weights proposed by Union are a good starting point for establishing a proper weather normalization methodology. The issue for the Board to consider is whether the 20 year trend methodology is a superior forecasting tool than the current 30 year moving average. The impetus to change methodologies is the hypothesis, supported by the evidence of Dr. Weaver, of a global warming trend.

Dr. Weaver's evidence does not support any particular weather normalization method. A number of parties argued for continuation of the 30 year methodology. LPMA and IGUA criticized the statistical analysis done by Union and argued for the continuation of the current practice, or a 20 year method with various proposed revenue adjustment mechanisms. Many parties pointed out that the 20 year proposed methodology would result in a net increase in rates.

IGUA and FONOM argued for a phasing in of any change in methodology. Union rejected this proposal and claimed that this would result in it failing to recover its costs, except during colder than normal weather.

Ratepayers are at risk for unutilized demand charges if the methodology overforecasts HDDs, but the ratepayers are also at risk for the cost of increased winter spot purchases if the methodology underforecasts HDDs.

The Board is concerned with the lack of clarity with respect to the statistical evidence. A number of parties explored whether an estimator derived from ordinary least squares was more or less efficient than using a more sophisticated regression technique. Union's inability to respond clearly is of concern, especially given the large impact that the proposed change in methodology has on its revenue requirement.

Both the 20-year trend and the 30-year average normalization methodologies have advantages in their application. The 20-year trend may track more through the middle of the data and will respond more quickly to changes in short-run trends, but will be more volatile. The 30-year average will respond more slowly to changes but it will be less volatile.

Union was unable to demonstrate that its proposal provided a clear and unambiguous improvement over the 30 year methodology. Nor is the Board convinced that the cited case: *Hemlock Valley Electrical Association* v. *British Columbia Utilities Commission* provides any precedent as to whether it is open to the Board in this case to choose a phased in approach. The OEB Act gives the Board clear authority to adopt any methodology it considers appropriate when setting rates.

In order to test the suitability of changing the normalization methodology, and in consideration of the principle of minimizing rate shock, the Board will allow Union, for 2004, to forecast HDDs based on a 70:30 weighting of the 30-year average forecast and 20-year trend forecast respectively. For each year thereafter, the Board will consider 5% declines and inclines to the weighting of the 30 year and 20 year methodology respectively until such time as a 50:50 weighting is in place.

With respect to operational planning, the Board directs Union to use the same forecast for operations planning as is used all other purposes. The Board also directs Union to report on the outcomes of using the hybrid model annually.

2.3 AFFILIATE RELATIONS

Union's Request

Union seeks to recover in rates the costs it incurs as a result of its shared services arrangements with its affiliates. These costs are $28.7 million in total.

Background

Duke Energy Corporation ("Duke") completed the purchase of Westcoast Energy Inc. ("WEI"), the parent company of Union, in March 2002. Following this transaction, Union became a participant in Duke's shared services business model. The use of this model results in the sharing of a broad range of senior management and support services across Duke's many business units, creating inter-company transactions between the Duke business units as they pay for services received, and charge for services provided to other units.

Union has previously shared services with affiliated companies through the WEI Corporate Centre. Under the Duke shared services business model, to which it is

K 5.1

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL AND VARIANCE ACCOUNT DETAILS
2006 ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT (2006 EPESDA)

		Col. 1
Line No.		2006 Actual ($000's)
1.	Gross revenue	1,451.7
2.	Material and service cost	(999.5)
3.	Internal resource cost	(102.0)
4.	Net revenue before sharing	350.2
5.	Shareholder portion of net revenues (50%)	(175.1)
6.	Ratepayer portion of net revenues (50%) transferred to the 2006 EPESDA	175.1

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ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL AND VARIANCE ACCOUNT DETAILS
2005/6 GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNTS (2005/6 GDARCDA) AND 2006 UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT (2006 URICDA)

Type/Category	Cost (000's)	Purpose
		2005 GDARCDA
GDAR Impact Analysis	$406.0	* Review and analysis of the GDAR rule and it's impact on systems and business process changes that would be required to be compliant. * Estimation of costs that would be incurred in order to implement the GDAR rule.
Total	**$406.0**	
		2006 GDARCDA
Requirements Analysis	$233.7	* GDAR requirements gathering and analysis sessions and development of a project implementation roadmap. A series of joint sessions between Enbridge and all service providers. The work was based on the impact of the GDAR rule and the requirements of the EBT standards published by the Board.
EnTRAC Systems Changes	$2,877.9	* Changes to the EnTRAC system that were required in order to be GDAR compliant. This included the design, development, and unit testing of all required changes including the point-to-point EBT Transaction system.
Customer Care Systems Changes	$1,813.7	* Changes to all Customer Care systems and design and implementation of new internal business processes that were required in order to be GDAR compliant. The system changes were made to CIS, LVB, LVTS, and ICSS to support the EBT standards.
Business Process Changes	$188.6	* Design, documentation and implementation of new business and IT support processes that were required to be GDAR compliant.
Training & Communication	$148.2	* Planning and implementation of a training program for internal and external stakeholders. The development and execution of a communication plan to ensure that all stakeholders were aware of GDAR related activities undertaken by Enbridge.
Quality Assurance	$347.9	* Planning and implementation of a Quality Assurance program to ensure that the systems and business processes changes completed put Enbridge in a position to meet GDAR compliance requirements. This includes working with the Market participants to develop a joint Market Test Plan.
GDAR Cutover Readiness	$65.5	* Planning for GDAR implementation in June, 07. This includes planning and analysis effort to assess all the activities to be performed during the cutover and working with market participants to develop a Market Cutover plan.
IT Infrastructure (Hardware/Software	$761.2	* Hardware, Software licenses, installation, and configuration required for the development, testing, and implementation of GDAR.
Program/Project Management/Subject Matter Experts/Additional Resources	$1,486.6	* Project/Program management resources required to manage the GDAR program as well as business and IT Subject Matter Experts required for GDAR requirements analysis, Systems design sessions, testing, and implementation of GDAR from January-December.
Total	**$7,923.3**	
		2006 URICDA
Requirements Analysis	$58.7	* Joint requirements analysis, validation, and project roadmapping sessions between Enbridge and Service provider for NGEIR implementation.
Tool Development	$284.2	Tool(s) designed and developed to automate (where possible) business process changes required for NGEIR implementation and augment the manual solution.
Business Process Changes	$44.6	Design, documentation, and implementation of new business processes required to implement NGEIR.
NGEIR Cutover	$1.7	Effort required for setting up and putting the NGEIR tool in production for use.
Project Management/Subject Matter Experts/Additional Resources	$91.3	Project/Program management resources required to manage the NGEIR program, Business Subject Matter experts for requirements, design, and implementation.
Total	**$480.5**	

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K5.2

Table 1
GDAR Cost Breakdown

Scope Item	Capital Costs (a)	Annual O&M Costs (b)	In-Service Date (c)
1. Implement EBT standards	$7.0 million	$40,000	January, 2007
2. ABC service for Large Volume	$2.5 million	$0	January, 2007
3. Bill-Ready Service	$8.7 million	$460,000	January, 2008
Total	$18.2 million	$500,000	

Consistent with the costs approved by the Board in the RP-2003-0063 Decision, these incremental costs are required for regulatory compliance and recovery is not contingent on Union demonstrating that any benefits outweigh the costs.

As indicated in the Board's November 15, 2005 Decision, all capital and operating costs prudently incurred to implement GDAR should be recovered from customers, and specifically from those customer classes that benefit from the implementation of GDAR. The purpose of GDAR was to improve retail natural gas competition in Ontario. Therefore, the costs to implement the Rule should be paid for by those who stand to benefit from the Rule.

Union's two-year implementation plan, which is consistent with the Board's November 15th Decision, means that final GDAR compliance will be achieved in stages. As shown in Table 1, the EBT standards and ABC service for large volume customers will come

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0021

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

Ontario Energy Board
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EXHIBIT No. K5.3
DATE February 2, 2007
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How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> "Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account".

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

K6.1

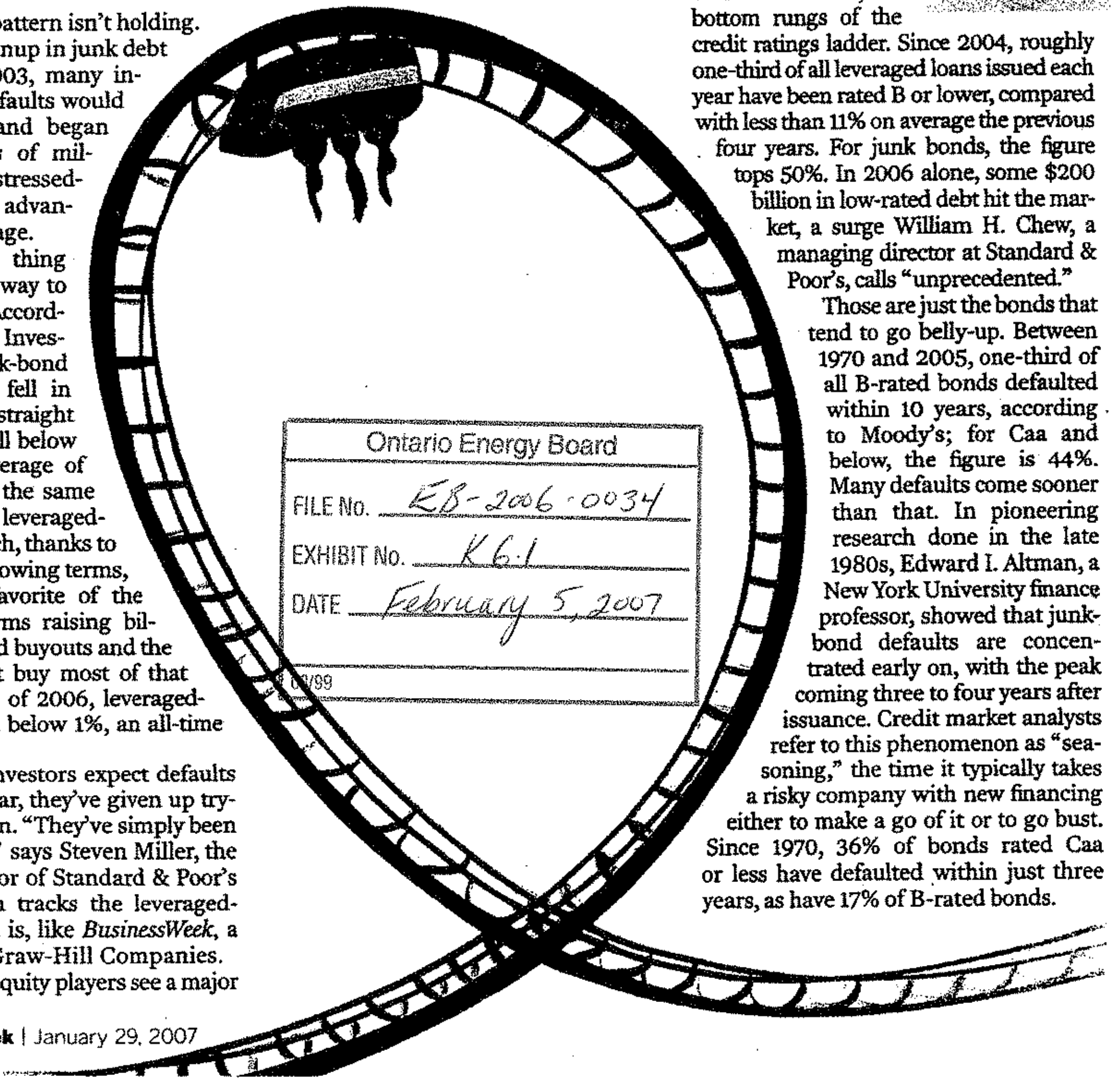
Junk Keeps Defying Gravity

If history is any guide, low-rated bonds and loans should be tanking. Here's why they're not

BY JANE SASSEEN

FOR DECADES THE JUNK-bond market has followed a pattern that's about as regular as spring following winter. Two to four years after a new wave of bonds hits the market, defaults on those bonds surge.

This time, the pattern isn't holding. Given the huge runup in junk debt that began in 2003, many investors figured defaults would spike last year and began raising hundreds of millions for new distressed-debt funds to take advantage of the wreckage.



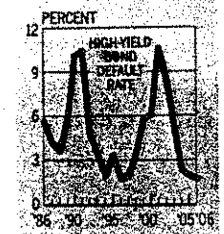
But a funny thing happened on the way to the meltdown: According to Moody's Investors Service, junk-bond defaults actually fell in 2006 for the fifth straight year, to 1.7%—well below the long-term average of 5%. The story is the same in the booming leveraged-loan market, which, thanks to more flexible borrowing terms, has become a favorite of the private equity firms raising billions for leveraged buyouts and the hedge funds that buy most of that debt. By the end of 2006, leveraged-loan defaults slid below 1%, an all-time low.

While many investors expect defaults to tick up this year, they've given up trying to call the turn. "They've simply been wrong too long," says Steven Miller, the managing director of Standard & Poor's LCD unit, which tracks the leveraged-loan market and is, like *BusinessWeek*, a unit of The McGraw-Hill Companies.

Some private equity players see a major structural shift at play: Greater liquidity across the capital markets and the explosion of sophisticated financial instruments, they say, are reducing the level of risk permanently. But others say the cycle is just being delayed, possibly leading to a harsher crash when it turns. "The big question is whether the excess money is simply giving weak companies all the rope they need to hang themselves," says David T. Hamilton, Moody's head of credit default research.

To see why some are worried, consider the record amounts of risky debt that have flooded the market in recent years. Start with junk bonds: New issuance has soared from $62 billion in 2002 to an average of $127 billion annually over the last four years. And that market has been dwarfed by the rise of leveraged loans, the higher-yielding bank loans that hedge funds and other investors are snapping up. Since 2002, the issuance of leveraged loans has more than tripled, to $480 billion last year, according to LCD.

NOWHERE TO GO BUT UP?



Data: Moody's Investors Service

It's not just the quantity of loans that's worrisome—it's also the quality. Much of the debt is rated B or Caa and below, the bottom rungs of the credit ratings ladder. Since 2004, roughly one-third of all leveraged loans issued each year have been rated B or lower, compared with less than 11% on average the previous four years. For junk bonds, the figure tops 50%. In 2006 alone, some $200 billion in low-rated debt hit the market, a surge William H. Chew, a managing director at Standard & Poor's, calls "unprecedented."

Those are just the bonds that tend to go belly-up. Between 1970 and 2005, one-third of all B-rated bonds defaulted within 10 years, according to Moody's; for Caa and below, the figure is 44%. Many defaults come sooner than that. In pioneering research done in the late 1980s, Edward I. Altman, a New York University finance professor, showed that junk-bond defaults are concentrated early on, with the peak coming three to four years after issuance. Credit market analysts refer to this phenomenon as "seasoning," the time it typically takes a risky company with new financing either to make a go of it or to go bust. Since 1970, 36% of bonds rated Caa or less have defaulted within just three years, as have 17% of B-rated bonds.

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But for now, that isn't happening, and the surge in LBO-fueled debt is likely to continue in 2007 as well. Interest rates remain astonishingly low. In 2003 junk-rated debt typically sold for 5 to 8 percentage points above the yield of the 10-year Treasury bond; that spread has since dropped to 3.4 points. "More and more people are buying very speculative debt, at pricing that just doesn't justify the risk," says Chew.

DEEPER POOLS

ALL OF WHICH LEADS to an obvious question: Why haven't defaults begun to kick up? Analysts cite a host of reasons, starting with the relatively strong economy and the recent muscle in profits. But the biggest factors are the enormous amount of money sloshing around and the changing structure of the debt market. Foreign investors are shipping gobs of cash into the U.S. At the same time, there has been an explosion of hedge funds, distressed debt traders, and others eager to buy junk-rated debt for the higher yields it offers, much of it chopped up and resold in other sophisticated financial instruments such as collateralized loan obligations. Together, these factors have combined to create unheard-of pools of liquidity. Not only has that helped keep a lid on interest rates—holding debt payments down—it has also made funding readily available even for struggling companies.

There's another reason, too: easy borrowing terms. Restrictions and stipulations based on the financial health of the debtor are practically nonexistent these days, in both exotic leveraged loans and ordinary corporate bonds. Historically, when borrowers have violated such basic rules, they've been forced into default. Now, says Martin S. Fridson, a high-yield bond market strategist who runs the New York-based firm FridsonVision, the restrictions "have been so watered down, there's nothing left to trip."

Fridson, like Altman, believes the pain is simply being put off and defaults will return to historic patterns. Both predict a small climb this year and a sharper rise in 2008. And they say the level and severity of defaults may be worse when they finally hit, precisely because weak players are continuing to pile on new debt. Altman believes defaults could eventually approach the 10% rates seen in the early 1990s, in the wake of the last LBO boom. "If companies can keep getting money, they will," says Fridson. "But a lot of it is going to keep companies alive that really should not be." ■

ILLUSTRATION BY JON KRAUSE; CHART BY ALBERTO MENA/BW

K6.2

PRICING SUPPLEMENT NO. 2 DATED DECEMBER 14, 2006
(To a Prospectus dated February 14, 2006)

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION INC.

Medium Term Notes
(Unsecured)

Terms of Issue

Principal Amount:	$175,000,000	Issue Price:	$99.958
Delivery Date:	December 19, 2006	Maturity Date:	December 17, 2021
Interest Rate:	4.77%	Interest Payment Date(s):	December 17 and June 17 commencing June 17, 2007
Yield to Maturity:	4.774%		

Redemption Provisions: The Medium Term Notes issued hereunder are redeemable prior to maturity, in whole or in part from time to time, at the option of the Corporation at a price equal to the Canada Yield Price on the business day next preceding the date on which notice of such redemption is given.

Agent(s):	RBC Dominion Securities Inc. BMO Nesbitt Burns Inc. CIBC World Markets Inc. HSBC Securities (Canada) Inc. National Bank Financial Inc. Scotia Capital Inc. TD Securities Inc.	Commission Rate:	0.45%
		CUSIP/ISIN Number:	CA29290ZAF77
		Registrar and Paying Agent:	Canadian Imperial Bank of Commerce
		Trustee:	CIBC Mellon Trust Company
Net Proceeds:	$174,139,000		

Documents Incorporated by Reference

The Prospectus dated February 14, 2006 into which this Pricing Supplement is deemed to be incorporated by reference also incorporates by reference certain other named disclosure documents of Enbridge Gas Distribution Inc., as follows:

(a) Consolidated comparative financial statements of the Corporation for the 12 month period ended December 31, 2005 and the auditors' report thereon;

(b) Management's discussion and analysis of financial condition and results of operations for the 12 month period ended December 31, 2005;

(c) Annual Information Form of the Corporation dated February 26, 2006 for the year ended December 31, 2005;

(d) Consolidated comparative interim financial statements (unaudited) of the Corporation for the nine-month period ended September 30, 2006; and

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K6.2
DATE February 5, 2007
08/99

EB-2006-0034

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2007.

CROSS-EXAMINATION REFERENCE BOOK on behalf of POLLUTION PROBE

February 5, 2007

KLIPPENSTEINS
Barristers & Solicitors
160 John St., 3rd Floor
Toronto ON M5V 2E5

Murray Klippenstein
Basil Alexander
Tel: (416) 598-0288
Fax: (416) 598-9520

Counsel for Pollution Probe

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Tab [Pages]	Contents [pages]
1	Board Staff Interrogatory #25 [1-3] • Filed: 2006-11-09, EB-2006-0034 (Enbridge 2007 Rates), Exhibit I, Tab 1, Schedule 25
2	Fuel Switching and Enbridge Gas Distribution by SeeLine Group Inc. dated February 2006 [4-6] • Filed: 2006-05-26, EB-2006-0021 (Natural Gas Generic DSM), Exhibit JT1.31 Written Submission of Enbridge Gas Distribution to Ontario Power Authority dated August 26, 2006 [7-10]
3	Pollution Probe Interrogatory #3 (REVISED) [11-20] • Revised: 2007-02-01, EB-2006-0034 (Enbridge 2007 Rates), Exhibit I, Tab 15, Schedule 25
4	EnergyLink Billing Insert [21-22]

BOARD STAFF INTERROGATORY #25

INTERROGATORY

Ref: D1/T8/S1

Issue Number: 3.3
Issue: Is the Company's proposed fuel switching program appropriate?

EGD has requested an amount of $5.0 million in new initiatives aimed at promoting fuel switching activities. Please provide a breakdown of costs and the activities associated with each of the cost components.

a) How many conversions will this new initiative achieve in each of the first five years of its implementation?

b) Please provide the impact of this initiative on the distribution revenue during the first five years of its implementation?

c) Has EGD embarked on any similar initiatives before? If "Yes", please provide details of these prior initiative including volumetric and revenue impacts.

d) Has the Company performed a cost/benefit analysis of this initiative? If "Yes", please provide a report of this study. If "Not", please prepare and provide a detailed cost/benefit analysis.

e) As part of this initiative, the Company plans to raise awareness of natural gas and educate consumers on its benefits versus other alternate energy sources. Has EGD considered partnering with other vendors or Union Gas on this initiative to realise scale economies or share costs? Please provide details on any partnership initiatives including cost sharing and potential benefits. If EGD has not entered into any partnership, please provide reasons for not partnering on a generic initiative.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

 2

RESPONSE

A breakdown of costs and activities associated with these initiatives is included in Table 1 of this response.

a) Please refer to Table 1, Column 3 for the participants that will result in 2007.

b) Please refer to Table 1, Column 7.

c) In 2006, the Company's planned fuel switching initiatives were also imbedded in the Market Development portfolio. The financial impact of this 2006 portfolio is summarized below. Please note this information was previously filed as EB-2005-0001, Exhibit I, Tab 5, Schedule 41, as corrected 2005-09-07.

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	Volume (million m3)	Revenue ($million)	O&M Cost ($million)	Measure Life NPV ($million)	TRC ($million)	SCT ($million)
Residential Market	29.5	2.2	4.7	1.9	43.5	55.7
Business Market	12.4	0.5	1.1	1.0	20.3	28.4
Total Market Development	41.9	2.7	5.8	2.9	63.8	84.1

d) Please refer to Table1, Column 8.

e) Enbridge Gas Distribution has considered partnering with vendors and Union Gas on this initiative to realize scale economies and/or sharing of costs. At this time, no detailed plans are available. Opportunities to reach consumers with a positive, common message about the benefits of natural gas for specific end-use applications will be explored.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Table 1

2007 Regulatory Budget

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 1
	RESIDENTIAL MARKET	Vol (10^6 m^3)	Number of Participants	Life	Program Costs ($)	Incremental Cost per Participant	5 Year Distribution Revenue ($m)	Life NPV ($m)	TRC ($m)	SCT ($m)
1	High Efficiency Furnace	6.49	3,174	18	108,000	800	3.70	2.31	22.95	25.02
2	ECM	0.33	5,000	18	-	550	0.12	0.19	(0.54)	(0.36
3	Mid Efficiency Furnace	0.30	123	18	19,850	400	0.17	0.11	1.11	1.21
4	Fireplace	1.77	5,303	12	170,690	700	0.68	0.61	(6.12)	(6.20
5	Grill/BBQ	0.07	1,477	12	20,200	250	0.03	0.01	(0.18)	(0.19
6	Range/Dryer/Front Load Axis Washer	1.26	12,966	12	30,300	300	0.48	0.49	0.03	0.20
7	Low Income (WH)-fuel switching	0.78	1,150	9	925,000	800	0.38	(0.56)	0.38	0.54
8	Interior Constr. Heat Res New Cons*	10.60	18,644	1	123,742	350	1.40	0.80	5.19	5.45
9	Interior Constr. Heat Small Comm*	0.37	107	1	17,916	350	0.02	0.00	0.35	0.36
10	Residential Fuel Switching (Water Heating)	1.03	1,518	9	358,000	600	0.47	(0.06)	1.79	1.99
11	Water Heating	0.99	2,500	9	49,100	600	0.39	0.26	1.49	1.68
12	Outdoor Living/Garage heating/Pool Heating	0.33	550	12	170,690	700	0.12	0.04	(1.11)	(1.30
13	EnergyLinkTM	8.00	22,933	12	1,036,300	466	3.04	2.06	1.30	1.93
		32.31	75,445		3,029,788		10.99	6.26	26.67	30.33
14							Less Overhead	(2.49)	(2.49)	(2.49
15							Net Benefits	3.77	24.18	27.84
	BUSINESS MARKET									
16	Multi - Family Housing	3.75	18	20	180,823	350,000	0.80	1.17	11.75	12.78
17	Forklift Conversion	1.26	139	15	40,600	15,000	0.26	0.33	5.53	5.66
18	Commercial Construction Heaters*	7.00	175	1	20,000	1,600	0.46	0.28	7.02	7.19
19	Institutional/Commercial/Industrial	0.52	1,000	20	20,000	1,000	0.15	0.24	1.52	1.66
20	Small Com'l Business Partners	1.24	55	15	36,702	2,000	0.32	0.38	5.20	5.55
21	Small Com'l Load Plus	1.96	700	15	87,264	2,500	0.48	0.60	6.46	6.94
22	Small Com'l Additions/NonComs	1.92	180	15	87,824	5,000	0.52	0.43	6.44	7.03
		17.65	2,267		473,213		2.99	3.42	43.92	46.80
23							Less Overhead	(1.68)	(1.68)	(1.68
24							Net Benefits	1.74	42.24	45.13
25							**Total Net Benefits**	**5.51**	**66.42**	**72.97**

* Volumes are fully effective in the 1st year; distribution revenue, NPV, TRC and SCT based on 1 year only.

FUEL SWITCHING AND ENBRIDGE GAS DISTRIBUTION

FOR ENBRIDGE GAS LIMITED

By
SeeLine Group Inc.
416-703-8695

February 2006

1.0 INTRODUCTION

As part of its support for Enbridge Gas Distribution (EGD) marketing efforts, SeeLine Group Inc (SLG) undertook an assessment of the proposed electric fuel switching program. The focus of the analysis was the determination of the Total Resource Cost Test (TRC) for the proposed electricity to gas fuel switching technologies. These technologies include space heating, water heating, cooking and clothes drying.

2.0 APPROACH

SLG conducted two analyses for this study. The first analysis used technology and program input assumptions provided by Enbridge (Fuel_Switching_Option 2 Master_may25.xls). The second analysis used some of the input assumptions supplied by Enbridge; however, electricity usage data for clothes dryers, ranges and water heaters, was supplemented by information currently available from the Ontario Energy Board.

Both TRC analyses were conducted using the benefit and cost definitions and structures as approved by the Ontario Energy Board where the cost is defined as the increased societal cost of natural gas (as expressed by the avoided costs), the incremental equipment cost and the associated utility program support costs. The benefits are the avoided resource costs associated with a reduction in electricity use.

The TRC assessments were conducted using SLG's SeeTool™ TRC calculator. This tool and approach replicates both the DSStrategist™ model used in the past by Enbridge and the common approach used by electric utilities in Ontario currently undertaking Conservation and Demand Management TRC planning and analysis exercises.

Electricity avoided costs used in the analysis are those provided by the Ontario Energy Board. Avoided costs are expressed in eight costing periods for energy (winter peak, winter mid-peak, winter off-peak, summer peak, summer mid-peak, summer off peak, shoulder peak and shoulder off peak) and one (summer) for peak (demand). As such, all electricity savings values must also be defined in the same manner.

In absence of gas costs used to evaluate system expansion projects, the company's DSM avoided gas costs were used for this analysis. These costs were used for the EBO 2005-0001 rate case evidence and provide a good proxy for examining fuel switching programs.

2.0 RESULTS

Results from the first phase of this analysis are summarized in the tables below. Table 1a provides a summary of the proposed fuel switching program using the lower equipment life values for each technology.

Table 1a. Summary of TRC Results using Enbridge Data and Lower Equipment Life Assumptions

Program Results with Lower Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (15 yrs)	$38,348,134	$ 49,310,597	$45,181,049	$29,497,987	$32,477,881	$194,815,647
Ranges (14 yrs)	$ 3,630,417	$ 4,594,486	$ 4,224,016	$ 2,831,876	$ 3,277,971	$ 18,558,766
Dryers (11 yrs)	$ 7,998,805	$ 10,638,713	$ 9,765,085	$ 6,255,385	$ 7,020,153	$ 41,698,142
Water Heaters (10 yrs)	$11,461,554	$ 35,878,424	$32,873,762	$21,615,245	$23,701,290	$125,530,276
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	$58,381,187	$100,424,227	$92,065,920	$80,202,502	$66,479,308	$377,553,142

* Marketing/Administration/Promotion Costs

Based on above results, the fuel switching program would provide positive net benefits for each year and technology as specified by the program assumptions. The total TRC net benefits for the full five years of the program are $377,553,142 (in 2006 dollars).

It should be noted that these and other TRC test results, do not include the $305,972,900 in incentive costs. These costs are merely transfer payments between the utility and the participant and therefore cancel each other out.

Table 1b. Summary of TRC Results using Enbridge Data and Higher Equipment Life Assumptions

Program Results with Higher Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (17 yrs)	$ 44,949,956	$ 57,878,105	$ 53,031,066	$ 34,576,213	$ 38,099,274	$ 228,534,613
Ranges (15 yrs)	$ 4,307,348	$ 5,541,070	$ 5,095,007	$ 3,362,696	$ 3,940,171	$ 22,246,293
Dryers (13 yrs)	$ 9,925,804	$ 13,315,623	$ 12,248,091	$ 7,765,907	$ 8,758,977	$ 52,014,403
Water Heaters (13 yrs)	$ 15,145,647	$ 47,437,924	$ 43,465,204	$ 28,566,563	$ 31,331,634	$ 165,946,972
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	$ 71,271,032	$ 124,174,730	$ 113,841,376	$ 74,273,388	$ 82,132,066	$ 465,682,552

* Marketing/Administration/Promotion Costs

As would be expected, the higher equipment life assumptions yield greater TRC net benefits as shown in Table 1b. This is largely due to the longer lifecycle of

Written Submission

Enbridge Gas Distribution to the Ontario Power Authority in the matter of the province's energy supply mix August 26, 2005

Introduction: Enbridge Gas Distribution ("Enbridge") is pleased to provide this response to the Call for Written Submissions issued by the Ontario Power Authority in the matter of the province's energy supply mix. The following considerations reflect Enbridge's 157-year history of anticipating and adapting to changing energy circumstances in Ontario, and meeting the changing needs of generations of customers.

Natural gas - Part of a diverse energy portfolio: Ontario's natural gas sector is well-positioned to play its part in realizing the government's stated goal of a diverse supply of competitively priced power within a conservation culture:

- ***Sufficient supply:*** There will be enough natural gas supply to meet future needs. Natural Resources Canada has calculated total remaining natural gas reserves in North America alone at 75 times current consumption levels. In addition, significant additional reserves have been and are being identified.

- ***Fair and reasonable prices:*** Natural gas is and will remain an economic energy choice. Based on the experience of Enbridge's own customers in recent years, natural gas has been on average about 39% less expensive than electricity and 20% less expensive than oil.

- ***Environmental benefits:*** Environment Canada has noted that natural gas-fired power generation emits the lowest level of greenhouse gases among all fossil fuels. In addition, an independent study released by the Ministry of Energy in April 2005 concluded that a combination of nuclear and natural gas-generated electricity was the lowest-cost energy scenario in terms of money, public health and the environment.

- ***Conservation culture:*** The natural gas sector has initiated a number of energy efficiency programs to help customers reduce the amount of natural gas they use. Programs implemented by Enbridge between 1995 and 2004 alone reduced consumption by the equivalent of the gas used by 620,000 homes in one year. Those same programs reduced carbon dioxide emissions by the equivalent of removing 750,000 cars from the road for one year.

- ***Advancing stated public policy objectives:*** As noted above, natural gas can advance the Ministry's stated desire for diversity of supply. It also advances the findings of an Ontario Energy Board ("OEB") report issued in March 2005, which recognized the important and growing role of natural gas and natural gas infrastructure in the province's energy system.

Fuel switching - The focus of this submission: There are a number of ways in which natural gas can contribute to the achievement of the province's stated energy needs and objectives. One way is through large scale electricity generation. Another is through distributed energy. Still another is through energy efficiency models that provide demand side management and other programs tailored to particular classes of customers.

The focus of this submission, however, is on another aspect of the natural gas component of a diverse energy mix. This aspect - fuel switching – entails the switching of customers from electric appliances to natural gas appliances that can perform the same chores, often in a more effective and cost-efficient way.

Fuel switching - The plan and the benefits: The remainder of this submission discusses a five-year plan for the switching of 1,043,425 furnaces, water heaters, ranges and dryers from electricity to natural gas. Under this initiative, the benefits to Ontario would include:

- ***Reduced electricity demand:*** Peak load electricity demand would be reduced by 1,490 megawatts.
- ***Avoided generation costs:*** The move to natural gas-fired appliances would realize avoided electricity generation costs of $1.146 billion.
- ***Decreased greenhouse gas emissions:*** The switch from electric to natural gas appliances would lower greenhouse gas emissions by 2.5 million tonnes.

Fuel switching - The potential for quick 'wins': One of the key attributes of the fuel switching initiative is the speed with which the benefits could be realized. This is due, in part, to the fact that the natural gas infrastructure and technology to implement such a program are already in place. There follow three areas or quick 'wins' that demonstrate the benefits that can be achieved for Ontario in short order, using existing technology, and building on current or reinforced infrastructure.

- ***Space heating:*** Electrical residential space heating can account for up to 60% of residential electricity use. Switching the space heating source from electricity to natural gas furnaces could save $1.1 billion in avoided generation costs.
- ***Water heating:*** Heating water electrically can total up to 20% of residential electricity use. Switching to natural gas tankless water heaters can increase energy efficiency and lower customer costs
- ***Helping low income residents:*** Approximately 14% of Ontario residents live at or near the poverty line. More than 50% of them use electric water heaters, which cost more to operate than natural gas heaters. Thus, people who can least afford it are paying more to heat their water than they have to. Switching their water heaters from electricity to natural gas has the potential to save this group some $146 million in avoided generation costs.

Fuel switching - The role of incentives: One way to encourage the implementation of any fuel switching initiative is to make the prospect attractive to customers. Here, as elsewhere in the economy, retail prices can influence consumer choices and buying decisions. The cost of purchasing new natural gas appliances, before the end of the useful life of existing electricity appliance stock, can be an impediment to change with many customers. This fact alone can deter consumers from pursuing the natural gas option, even though they can realize significant cost savings over the life of those natural gas appliances.

One way to encourage consumers to choose the natural gas option, and to realize the potential benefits for the province, is through the use of direct-to-ratepayer incentives for purchasing natural gas appliances. Such incentives could be provided in one of two ways. The first is by the provincial government itself. The second is through the regulatory process in which local utilities would factor such incentives into their rate structure, build cost recovery plans into their rate submissions, and seek approval of those submissions through the OEB in the normal course.

Either way, if direct-to-ratepayer incentives were provided for 50% of the purchase price of switching to natural gas appliances, and as the Fuel Switching – Summary Results document appended to this submission indicate, Ontario would still realize net avoided generation costs of $617 million under the proposed five-year fuel switching program.

Fuel switching - Other considerations: Enbridge recognizes that other considerations are associated with the proposed fuel switching initiative. One is that the cost of the related system expansion would fall within natural gas utility rates. Another is that the demand for natural gas would increase. Analysis suggests, however, that the increased use would equal just 0.2% of total North American demand. A third factor is the proposed five-year timetable itself. Enbridge believes that this schedule, while aggressive, is achievable using current technology and building on current infrastructure.

In conclusion – Natural gas, fuel switching, and the benefits to Ontario: By way of summary, and in support of its proposed five-year fuel switching initiative from electric to natural gas appliances, Enbridge Gas Distribution submits that:

- **Natural gas can do its part:** Natural gas is well-equipped to play a significant role within Ontario's changing energy mix. It is plentiful, economical, and environmentally sound.

- **Fuel switching is a viable and achievable initiative:** Fuel switching from electric to natural gas appliances - an initiative that is being pursued elsewhere - can be achieved at low risk through existing infrastructure and technology.

- **Ontario will benefit:** The fuel switching initiative will, among other things, address the government's stated policy objectives, reduce electricity demand, avoid generation costs and lower greenhouse gas emissions.

Fuel Switching– Summary Results

	Over 5 years
Megawatts Saved (Diversified Demand)	1,490
Net GHG Emissions Reduced	2.5 million tonnes
Cost of 1,490 MW NG Fired Generation	$1.146 billion
Incentive Cost (@ 50% of replacement)	$0.529 billion
Avoided Generation Cost	$0.617 billion
Ratio of NG Fired Generation Costs to Incentive	2 to 1
Total Electric Appliances switched	1,043,425
Furnaces	114,875
Water Heaters	279,200
Ranges	323,000
Dryers	326,350

Market Transformation Assumptions

Enbridge Gas Distribution Inc.			Market Penetration				
		5 Years		Existing Home		New Homes	
Residential Customers	1,525,000		Appliance	Current	Proposed	Current	Proposed
New Home additions	40,000	200,000	Furnaces	90%	93%	98%	100%
System Expansion/year	4,500	22,500	Water Heaters	86%	93%	91%	96%
Infill Customers/year	5,000	25,000	Ranges	24%	34%	24%	34%
			Dryers	30%	46%	30%	40%

System Expansion	35% electricity / 65% oil
Infill Customers	35% electricity / 65% oil
Heating only	35% electricity / 65% oil

Union Gas			Market Penetration				
		5 Years		Existing Home		New Homes	
Residential Customers	1,200,000		Appliance	Current	Proposed	Current	Proposed
New Home additions	20,000	100,000	Furnaces	92%	95%	100%	100%
System Expansion/year	1,000	5,000	Water Heaters	85%	92%	86%	96%
Infill Customers/year	4,000	20,000	Ranges	19%	29%	19%	29%
			Dryers	21%	31%	21%	31%

System Expansion	50% electricity / 50% oil
Infill Customers	50% electricity / 50% oil
Heating only	50% electricity / 50% oil

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POLLUTION PROBE INTERROGATORY #3

INTERROGATORY

Ref: D1/T2S1 Attachment A

Issue Number: 3.2
Issue: Is the overall level of the 2007 Operation and Maintenance Budget appropriate?

With respect to each of the Opportunity Development Department's programmes, please provide each programme's forecast Total Resource Cost (TRC) Test net benefits. In addition, please provide the input assumptions used to calculate each programme's TRC Test net benefits.

RESPONSE

In the Company's response to Board Staff Interrogatory #25 (Exhibit I, Tab 1, Schedule 25) information on the Company's Market Development programs, including TRC calculations, was provided. The Company has not completed TRC calculations for any of its other activities. To provide additional clarity, the Company is able to provide the following:

A breakdown by department of the Opportunity Development Budget developed for the purposes of the Company's original application is shown in Table 1.

Table 2 contains a breakdown of the Residential and Business Market programs within the Market Development department and additional detail for the EnergyLink™ program.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Table 1

Opportunity Development Department Breakdown O&M	2005 Actual	2006 Bridge Year Estimate	2007 Test Year Budget
Market Development			
Salaries + Employee Expenses	967	1,160	1,703
Program Expenses	909	2,417	7,363
Sub Total	1,876	3,577	9,066
* *Energy Opportunities*			
Salaries + Employee Expenses	771	883	1,078
Program Expenses	623	294	1,431
Sub Total	1,394	1,177	2,509
* *Business Development & Strategy*			
Salaries + Employee Expenses	1,426	1,072	1,709
Program Expenses	1,294	595	1,324
Sub Total	2,720	1,667	3,033
Storage Operations			
Salaries + Employee Expenses	2,479	2,349	2,815
Maintenance & Operating Expenses	3,957	3,945	4,914
Sub Total	6,436	6,294	7,729
Energy Policy & Analysis			
Salaries + Employee Expenses	455	923	1,034
Operating Expenses	92	161	319
SLA's	4,338	2,500	2,625
Sub Total	4,885	3,584	3,978
Business Intelligence & Support			
Salaries + Employee Expenses	1,450	1,551	1,880
Operating Expenses	560	508	727
Sub Total	2,010	2,059	2,607
Opportunity Development Administration			
Salaries + Employee Expenses	698	761	766
Operating Expenses	12	89	126
Sub Total	710	850	892
Summary			
Salaries + Employee Expenses	8,246	8,699	10,985
Program & Operating Expenses	7,447	8,009	16,204
SLA	4,338	2,500	2,625
NGV	878	1,041	1,049
Total Expenses	20,909	20,249	30,863

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Table 2

MARKET DEVELOPMENT FIXED AND VARIABLE COSTS		Fixed ($000,000)	Variable Incentives ($000,000)	Total ($000,000)
Residential	**Initiative**			
	High Efficiency Furnace	$0.022	$0.086	$0.108
	Mid Efficiency Furnace	$0.000	$0.020	$0.020
	Fireplace	$0.171	$0.000	$0.171
	Grill/BBQ	$0.020	$0.000	$0.020
	Range/Dryer/Front Load Axis Washer	$0.030	$0.000	$0.030
	Low Income (WH)	$0.034	$0.891	$0.925
	Interior Constr. Heat Res New Cons	$0.124	$0.000	$0.124
	Interior Constr. Heat Small Comm	$0.018	$0.000	$0.018
	Residential Fuel Switching (Water Heating)	$0.072	$0.286	$0.358
	ECM	$0.000	$0.000	$0.000
	Water Heating	$0.000	$0.049	$0.049
	Outdoor Living/Garage heating/Pool Heating	$0.171	$0.000	$0.171
	EnergyLink™ (See Note 1 For Assumptions)	$0.445	$0.592	$1.036
	Residential Overheads	$2.487	$0.000	$2.487
		$3.592	$1.925	**$5.516**
Business Markets	**Initiative**			
	Multi-Family Housing	$0.181	$0.000	$0.181
	Forklift Conversion	$0.007	$0.034	$0.041
	Commercial Construction Heaters	$0.020	$0.000	$0.020
	Institutional/Comm/Industrial	$0.020	$0.000	$0.020
	Small Comm. Business Partners	$0.016	$0.020	$0.037
	Small Comm. Load Plus	$0.010	$0.077	$0.087
	Small Comm. Additions/Noncoms	$0.024	$0.064	$0.088
	Business Markets Overheads	$1.680	$0.000	$1.679
Total Bus. Markets		$1.958	$0.195	**$2.152**
Marketing Admin		$0.358	$0.000	$0.358
		$0.358	$0.000	**$0.358**
Marketing Communications		$1.040	$0.000	$1.040
		$1.040	$0.000	**$1.040**
Market Development Total		**$6.949**	**$2.120**	**$9.067**

Note 1: 2007 EnergyLink Program Assumptions	Participants	Volumes (000 m^3)
Furnace	1,200	2,454
Water Heater	2,500	1,702
Dryer	6,483	726
Fireplace	5,303	1,771
Ranges	6,483	525
Lifestyle Products	700	777
ECM	262	48
Total	**22,931**	**8,003**

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Business Development & Strategy (BDS) Department

The following paragraphs and Table 3 provides descriptions of the primary initiatives and programs included in the Business Development & Strategy as filed Budgets.

The Energy Technology (ET) group which operates with the BDS department creates new opportunities for added and retained load initiatives, energy efficient technologies, and improved operational efficiencies by influencing and accelerating technology development in the market. These initiatives provide significant customer, environmental and Company benefits.

The planned technology development projects for 2007 cover all market sectors as well as distribution-related technology development projects. In 2007, ET will also focus on new customer segments like power generation, small scale distributed energy, natural gas cooling and BTU metering in multi-residential buildings.

As Enbridge continues to face an increasingly uncertain energy market in terms of price, market share and environmental pressures, technology development efforts become even more important. It is clear from the actions of the Provincial Government that the Province is determined to find cost effective, environmentally superior options to address the province's electricity supply issues, and that natural gas is part of the solution. To develop technology options that meet our customers' needs, the Company must play an active role in influencing technology development in North America.

Energy Technology professionals work with marketing personnel to help identify utilization technology projects that have a strategic market fit and also have a high expectation of success. Energy Technology also works with clients in Operations and Engineering to identify initiatives which enhance operational performance and efficiency, safety, and reliability.

In 2006, Energy Technology activities achieved a benefit: cost ratio of 2.1:1. A similar level of benefits is expected in 2007. Additionally, the Department is able to leverage $8 of external funding for technology development for every $1 of funds invested by the Company.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Table 3

Energy Technology Projects

Initiative	Description
Ultrasonic Cased Pipe Inspection	Development of a long-range guided wave ultrasonic technology (UT) for inspection of cased pipe. The project involves adapting technology currently used for above-ground applications.
Service Abandonment Plug	Development of an elastomeric expansion plug and applicator device, which will be used to cease natural gas flow when performing a COAM ("cut-off at main") operation.
Keyhole Service Line Installation	Development of a process to install PE service lines through a keyhole, by a combination of sourcing and developing the necessary tools.
Gate valves	To evaluate the performance of a new NPS 4 Steel gate valve to provide an alternative product with reduced costs compared to the standard NPS 4 Steel gate valves. A pilot program is being conducted.
Remote corrosion monitoring	Develop a new methodology for remote corrosion monitoring equipment which is more efficient and has lower costs compared to the current manual corrosion monitoring methodology. A pilot program is being conducted.
Residential Cogeneration	Lab/field demonstration of residential cogeneration units. Deal with issues in Canadian market to ease entry for product manufacturers.
Building Recommissioning	Test and document discrete incremental improvements in operation and equipment of older buildings. Provide support through empirical test data.
Water Heating	Installation, testing and data collection of instantaneous boiler performance. Compare efficiency gains against baseline data collected with a traditional boiler/storage system.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Initiative	Description
Roof Top Units & Make Up Air Units	Investigate actual efficiency of installed units.
Snow Melter	Development of a direct-contact boiler driven snow-melting system. For >10 MMBTU/hr localized municipal zone operation (i.e. semi-mobile units).
Powder Coat Furnace	High-temperature gas-fired infra-red furnace. Originally developed for plastic thermoforming to be assessed for powder-coating.
Multi-Res Showcase Building	Develop metering options and alternatives to position natural gas as an affordable option for vertical sub-divisions.
Direct Flame Impingement Furnaces	Commercialize open-flame furnaces for both ferrous and non-ferrous applications.
Gas Fryer Project	Beta-testing of a new commercial fryer. The fryer will have 10% improved efficiency and reduced oil consumption.
Pressure Cooker Project	Completing the Beta-testing of a new commercial pressure cooker. The cooker will have 20% improved efficiency and design improvements.
Gas Dryer Project	Development of how to guide pertaining to the fuel switching opportunities in the Gas dryer, multi-residential arena. The development project will include the measurement and performance benefits of makeup air systems as well as active and passive ventilation systems.
Thermal Remediation	Develop a process to perform remediation of food processing facilities.
Airplane Deicing	Beta testing of an Infra-red de-icing system for commercial aircraft.
Dishwasher/Warewasher	Developing a gas powered ware washer for the 200-300 seat restaurant market.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Initiative	Description
High efficiency Broiler	Developing a high efficiency broiler.
Micro turbine demonstration	Verify performance for this technology in a field test at a commercial building site.
Ground Source Heat Pump	Assess efficiency and performance of specific units through field testing.
High efficiency heat recovery	Development of an enthalpy energy transfer membrane for Industrial boilers to recover energy through exhaust.
Organic Rankine Cycle generator as replacement for absorption	A study of absorption systems compared to "Organic Rankine Cycle" generator heat conversion technology for large Commercial combined heat & power.
Integrated Fireplace	Develop product to stage of commercialization.
Residential Absorption Heat Pump	Development of a high efficiency absorption heat pump for residential applications.

The Sustainable Energy group (SE) which operates within the BDS department provides strategic leadership to EGD in relation to Corporate Social Responsibility efforts. As the utility industry moves into a carbon-constrained future, the SE group also takes a lead role in tracking and reporting EGD's GHG emissions and develops action plans and targets for reduction of these emissions. SE also plays an active role in assessing renewable energy technologies as an effective means to help customers use energy more efficiently.

The SE group supports four key EGD program areas:

1) Environmental Technology Development

2) Climate Change and Emissions Reporting

3) Growth Initiatives

4) Corporate Social Responsibility (CSR)

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Energy Opportunities Department

The Energy Opportunities department is advancing the markets for natural gas' continued adoption within the emerging sectors of distributed generation, district energy, and advanced energy technologies, such as stationary fuel cells. These initiatives strengthen the position of natural gas in the electricity sector as well as establish improved environmental performance in a rapidly evolving provincial energy sector.

The Distributed Energy (DE) group is responsible for developing and servicing all forms of gas-fired generation within the EGD franchise. The market ranges from small 30 kilowatt micro turbines to large 990 megawatt combined cycle facilities. These installations can vary in use from on-site backup generators to central merchant plants.

In 2007, EGDI will continue to service, support and facilitate gas-fired generation. Examples of development efforts intended for 2007 include:

- Commissioning of gas delivery to Goreway Station.
- Commencing of Portlands Energy Centre gas delivery project.
- Commencing of Thorold Cogen. L.P. gas delivery project.
- Supporting proponents participating in the gas generation projects (e.g. York region, Southwest Greater Toronto Area) identified in the Ontario Power Authority's (OPA) Integrated Power System Plan (IPSP).
- Servicing proponents participating in OPA's Phase II of Combined Heat & Power Request For proposal (CHP RFP Phase II)
- Facilitating proponents participating in the OPA's Clean Energy Standard Offer Program (CESOP) and other small generation projects.
- Facilitating the use of gas-fired generation in backup, demand response and peak-shaving operations.

In addition, the DE group continues to work with customers and potential customers to develop and improve services. Examples are the new ancillary services as tabled in the Natural Gas Electricity Interface Review (NGEIR) decisions which will be effective in 2007.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

For smaller scale generation, EGD works with business partners to reduce or eliminate barriers to the adoption of distributed generation, and assist customers in selecting solutions. The Company supports customers' needs through the provision of technical, analytical, regulatory and attachment support. For example, support is provided for the further development of Combined Heat Emergency Power (CHeP) projects.

The benefits from these efforts include supplying much needed power to the Toronto area, with a suite of ancillary services which will provide the tools for the power generators to address their load-balancing needs. The Company will also facilitate true distributed generation in congested areas within EGD's franchise area and this will provide benefits through greater flexibility and responsiveness to meet customers' energy needs. These benefits also include energy supply security, higher total energy efficiency, reduced electrical transmission loss and congestion, and reduced environmental emissions.

Fuel cell technologies are also addressed within the Energy Opportunities department. Large stationary fuel cells are a form of distributed generation; however, compared to combustion-based generation, the technology's unique environmental and technical attributes provide gas utilities with a means of embedding enhanced value in the electricity that is generated from fuel cells. The low environmental impact of electricity that is generated from natural gas fuel cells has similar characteristics to many renewable electricity supplies. The unparalleled efficiencies are a direct fit with the utility's advancement of energy efficiency, and adoption of the technology within Enbridge's franchise area will strengthen the company's base of embedded base-load technologies.

The 2007 fuel cell activities support the company's pilot plant development, which is being implemented at 500 Consumers Road in Toronto. Performance monitoring, reporting and verification activities have been budgeted to document the pilot plant's performance following its commissioning. To assist the company, and its customers, with future technology adoption, the Energy Opportunities Department will implement a communications plan and market transformation plan to advance the needed industry and government engagement that will establish supportive policies for this technology.

Specific technology development plans for 2007 include the establishment of the needed service/support infrastructure for the pilot plant and subsequent technology adoption. This includes a number of training programs for Company employees and third party service providers.

Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
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N. Ryckman

The plant commissioning will result in expenses related to the maintenance of the pilot plant. These expenses have been budgeted within the Energy Opportunities department for 2007; however, once the plant's commissioning activities are complete and the plant moves to commercial acceptance (projected for Q1-2008), the maintenance expenses will be offset by the pilot plant revenues derived from the sale of the project's electricity.

The distributed energy market continues to evolve in Ontario. Both distributed generation and fuel cells can be embedded within a distributed energy system. In addition to the sector specific activities listed for distributed generation and fuel cells, Energy Opportunities will continue to engage industry stakeholders who are working to establish specific distributed energy investments in Enbridge's franchise area.

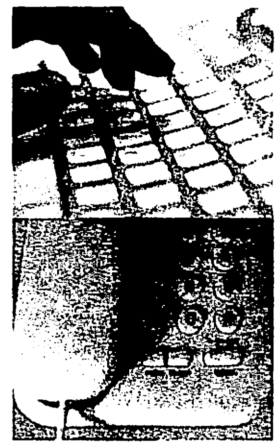
Witnesses: S. Clinesmith
P. Green
K. Lakatos-Hayward
P. Squires
N. Ryckman

Welcome to EnergyLink™, the new source for all your natural gas needs

EnergyLink™ is a new program brought to you by Enbridge Gas Distribution. It will help you locate qualified natural gas contractors in your area, as well as provide you with the most up-to-date information and links regarding natural gas products and services.

Your link to a one-stop referral system

When you contact EnergyLink™ (by internet or by phone) and indicate which natural gas service you require, EnergyLink™ will provide you with up to three referrals to qualified natural gas contractors in your area. It's that simple!



Your link to peace-of-mind

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22

K6.4

EB-20006-0034

Before the Ontario Energy Board

Enbridge 2007 Test Year Rate Case

Cross Examination Materials filed by Green Energy Coalition

Ontario Energy Board

FILE No. EB-2006-0034

EXHIBIT No. K6.4

DATE February 5, 2007

08/99

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
Calendar Year Ending December 31, 2006

Line No.	Particulars ($ 000's)	Estimate 2006
1	Finance	$ 12,362
2	Customer Care Service Charges (including CIS)	105,216
3	Customer Care Internal Costs	3,200
4	Provision for Uncollectibles	15,570
5	Regulatory Affairs	12,118
6	Law, Corporate Security & LR&PA	1,612
7	Operations	46,908
8	Information Technology	20,491
9	Opportunity Development (excluding DSM)	20,249
10	Human Resources (excluding benefits)	17,377
11	Benefits	21,301
12	Engineering	26,976
13	Public and Government Affairs	4,345
14	Non Departmental Expenses	4,127
15	Corporate Allocations (including direct costs)	24,761
16	Total	336,613
17	Capitalization (A&G)	(18,071)
18	Total Net Utility Operating and Maintenance Expense, Excluding DSM	318,542
19	Demand Side Management Programs (DSM)	18,914
20	Total Net Utility Operating and Maintenance Expense	$ 337,456

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.
2) LR&PA corresponds to Legal, Regulatory Affairs and Public Affairs Admin.

Witnesses: D. Kelly
T. Ladanyi
A. Urquhart

mid-1990's). Additional analytical support was required from other departments (i.e., Finance) that is now provided or augmented by departments in Enbridge Inc. (Corporate Controller Department), enabling further efficiencies to be gained. Services from the Senior Leadership, including the CEO, Group Vice President Gas Strategy & Corporate Development Department, as well as Treasury are also required to ensure that Enbridge Gas Distribution's strategic plan and financial long-range plan receives approval from the Board of Directors. This activity would be required on a stand alone basis and is not currently performed within Enbridge Gas Distribution.

2006 Budget Forecast

64. The 2006 Budget forecast of $18.5 million is comprised of the following: Market Development ($4.7 million); Sustainable Growth ($3.7 million); EOS and EI SLA contracts ($4.5 million); Business Support ($2.2 million); Energy Policy & Analysis ($1.0 million); OD Administration ($1.0 million); Strategic Planning ($0.2 million); and EI charges of ($1.2 million).

Table 1

Department Budget for 2006

	Col. 1 Item	Col.2 Amount ($millions)	
1	Salaries, Employee Training and Expenses	$	6.4
2	Program Cost	$	6.4
3	Gas Supply & Gas Control Agreements	$	4.5
4	Sub-Total	$	17.3
5	Cost charged by affiliates	$	1.2
6	Cost charged to affiliates	$	-
7	Total	$	18.5

Note: Excluding DSM, NGV and Gas Storage costs

Enbridge Gas Distribution
Operating and Maintenance Expense by Department
Calendar Year Ending December 31, 2007

Line No.	Particulars ($ 000's)	Budget 2007
1	Finance	$ 12,492
2	Customer Care Service Charges (including CIS)	101,605
3	Customer Care Internal Costs	3,422
4	Provision for Uncollectibles	15,105
5	Regulatory Affairs	11,710
6	Law, Corporate Security & LR&PA	1,838
7	Operations	52,905
8	Information Technology	23,810
9	Opportunity Development (excluding DSM)	30,863
10	Human Resources (excluding benefits)	19,222
11	Benefits	23,040
12	Engineering	33,497
13	Public and Government Affairs	5,576
14	Non Departmental Expenses	4,953
15	Corporate Allocations (including direct costs)	22,886
16	Total	362,924
17	Capitalization (A&G)	(19,134)
18	Total Net Utility Operating and Maintenance Expense, Excluding DSM	343,790
19	Demand Side Management Programs (DSM)	20,332
20	Total Net Utility Operating and Maintenance Expense	$ 364,122

Notes:
1) Departmental O&M costs are net of capitalization, non-utility allocations and other utility adjustments.
2) LR&PA corresponds to Legal, Regulatory Affairs and Public Affairs Admin.

Witnesses: D. Kelly
T. Ladanyi
A. Urquhart

GREEN ENERGY COALITION INTERROGATORY #1

INTERROGATORY

Ref. D1/T8/S1

Issue Number 3.3

Issue: Is the proposed increase of $5.0 million in Market Development Initiatives related to promoting fuel switching activities appropriate?

i) Please provide any analyses or estimates of cost-effective potential, that the company has in regard to fuel switching.

ii) Please file copies of any presentations to the Enbridge Board or to external entities such as the OPA on fuel switching that the company has given in the last two years.

iii) Please indicate the amount of the existing market development budget that has been used specifically for fuel switching promotion in recent years and provide detail for those expenditures.

iv) Please break out the intended use of the $5 million and any portion of the existing Marketing budget that will also be used to promote fuel switching as between research, advertising, customer incentives etc. to the extent known at this time.

v) The company notes that water heating is a priority in the near term. How will the company address the higher first cost issue for different market sectors? What plans if any are being considered for tank rentals?

vi) Please discuss the short term and long term rate implications for existing customers of various types of fuel switched load including the impacts from the market development expenditures themselves.

vii) Please provide an analysis of the opportunity and costs for low income customer water tank fuel switching assuming 100% of incremental costs are being borne as a program cost of the utility and provide details of any alternative strategy that the company is considering to address this identified priority.

Witnesses: S. Clinesmith
P. Green
P. Squires

vii) Please detail any plans or plans being considered to utilize affiliates or a dealer network or similar approach to encourage fuel switching. How will the company address concerns of the HVAC industry about the need to avoid obtaining unfair competitive advantage for affiliates?

viii) In responding to Board Staff's request for a cost benefit/analysis, please ensure that an analysis of the societal benefits of fuel switching is included.

RESPONSE

i) The following table summarizes the fuel switching potential that could be realized in the Enbridge Gas Distribution Franchise area. Col. 2 represent the total technical potential of natural gas units, based on existing market penetration for those end uses. Col. 3 represent the incremental market potential under one possible fuel switching scenario that involves a customer incentive of 50% of the capital cost of the equipment:

	Col. 1	Col. 2 Total Technical Potential (# of units)	Col. 3 Incremental Market Potential Over 5 Yrs. (# of units)
1	Furnaces	153,000	66,000
2	Water Heaters	214,000	161,000
3	Ranges	1,160,000	187,000
4	Clothes Dryers	1,100,000	190,000

This scenario is cost effective from a Total Resource Cost perspective, as presented in table 1a of the SeeLine report entitled "Fuel Switching and Enbridge Gas Distribution" (February 2006), filed in response to Consumers Council of Canada interrogatory #38 at Exhibit I, Tab 7 Schedule 38.

ii) Please refer to attached presentations:
Copy of presentation by Jim Schultz to the OEN – November 25, 2005
Copy of presentation by James Fidler to IndEco Strategic Consulting, January 2006.
Copy of presentation to Justice Committee by Lino Luison February 6, 2006

Witnesses: S. Clinesmith
P. Green
P. Squires

iii) Fuel switching has been an integral part of the Company's growth initiatives for many years, although the programs have not been explicitly labeled as such. Please refer to Board Staff interrogatory 25 (c) for a summary of the financial impacts of the Company's growth programs for 2006, as filed in EB-2005-0001. The Company's fuel switching initiatives were imbedded in this portfolio.

iv) The following table breaks out the proposed $5 million increase in the Market Development budget into fixed and variable costs. Fixed costs will include research, promotional material, training, and program development costs, and variable costs include program incentives.

	Fixed Costs $ millions	Variable Costs $ millions	Total 2007 Increment $ millions
Residential	0.9	2.2	3.1
Business Markets	0.9	0.2	1.1
Marketing Communications	0.8	0.0	0.8
Total	2.6	2.4	5.0

v) Enbridge Gas Distribution is currently testing various offers and incentive levels for conversion to gas water heating on a small scale, in localized segments of the franchise area, to help the Company determine the threshold incentive level that motivates fuel conversion for a typical residential customer. In the low income market segment, Enbridge Gas Distribution assumes that a much higher share – possibly 100% - of the incremental cost of a gas water heater would have to be borne by the program delivery agent(s). The Company is also in consultation with water heater rental companies to explore rental offers that make the conversion more attractive to consumers.

vi) Typically market development activities such as fuel-switching do not provide revenue that is in excess of the costs of the first year. For example, costs that are used to stimulate the installation of a natural gas water heater are expended up front, yet the revenue generated from the water heater installation will be realized over the next 10 to 15 years. In addition, in the first year of attachment customers are attached at different times throughout the year and consequently do not provide a full year of revenue. For those customers that require a natural gas main extension and service the attachment is evaluated for financial feasibility using the EBO 188 Feasibility Guidelines which uses rates and revenue horizons based on the rate class (e.g., residential is based on a 40 year revenue horizon). Generally speaking, the short term negative rate impacts are more than offset by the longer term benefits, and overall rates should be lower as the result of programs.

vii) Enbridge Gas Distribution has not completed a full analysis of the opportunity and costs for low income customer water tank fuel switching. The Company is proposing to spend $925,000 on this program in 2007 and recognizes that if this budget must cover 100% of incremental costs plus program fixed costs, the potential number of participants is limited. For this reason, the Company will consider alternate arrangements for program delivery such as partnerships with other organizations to offset incentive costs, and is investigating the potential for creative rental offers for low income consumers.

viii) Market development activities will work to optimize the use of a variety of external partners across all market disciplines in efforts to promote cost-effective fuel-switching activities across all market sectors. In the residential sector, Enbridge Gas Distribution will use as one of its channels the Energylink™ Program to connect customers with professional contractors and retailers to find the natural gas energy solutions they need. The Energylink™ Program does not provide any additional advantage to any affiliates. Enbridge Gas Distribution does have a vested interest in market share retention and market share growth of natural gas burner-tip applications with existing and new natural gas customers. Enbridge Gas Distribution will continue to work with a diverse group of natural gas industry players across all market sectors to effectively deliver cost-effective programs.

ix) Please refer to Board Staff interrogatory #25 at Exhibit I, Tab 1, Schedule 25.

Witnesses: S. Clinesmith
P. Green
P. Squires

BOARD STAFF INTERROGATORY #25

INTERROGATORY

Ref: D1/T8/S1

Issue Number: 3.3
Issue: Is the Company's proposed fuel switching program appropriate?

EGD has requested an amount of $5.0 million in new initiatives aimed at promoting fuel switching activities. Please provide a breakdown of costs and the activities associated with each of the cost components.

a) How many conversions will this new initiative achieve in each of the first five years of its implementation?

b) Please provide the impact of this initiative on the distribution revenue during the first five years of its implementation?

c) Has EGD embarked on any similar initiatives before? If "Yes", please provide details of these prior initiative including volumetric and revenue impacts.

d) Has the Company performed a cost/benefit analysis of this initiative? If "Yes", please provide a report of this study. If "Not", please prepare and provide a detailed cost/benefit analysis.

e) As part of this initiative, the Company plans to raise awareness of natural gas and educate consumers on its benefits versus other alternate energy sources. Has EGD considered partnering with other vendors or Union Gas on this initiative to realise scale economies or share costs? Please provide details on any partnership initiatives including cost sharing and potential benefits. If EGD has not entered into any partnership, please provide reasons for not partnering on a generic initiative.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

RESPONSE

A breakdown of costs and activities associated with these initiatives is included in Table 1 of this response.

a) Please refer to Table 1, Column 3 for the participants that will result in 2007.

b) Please refer to Table 1, Column 7.

c) In 2006, the Company's planned fuel switching initiatives were also imbedded in the Market Development portfolio. The financial impact of this 2006 portfolio is summarized below. Please note this information was previously filed as EB-2005-0001, Exhibit I, Tab 5, Schedule 41, as corrected 2005-09-07.

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
	Volume (million m3)	Revenue ($million)	O&M Cost ($million)	Measure Life NPV ($million)	TRC ($million)	SCT ($million)
Residential Market	29.5	2.2	4.7	1.9	43.5	55.7
Business Market	12.4	0.5	1.1	1.0	20.3	28.4
Total Market Development	41.9	2.7	5.8	2.9	63.8	84.1

d) Please refer to Table1, Column 8.

e) Enbridge Gas Distribution has considered partnering with vendors and Union Gas on this initiative to realize scale economies and/or sharing of costs. At this time, no detailed plans are available. Opportunities to reach consumers with a positive, common message about the benefits of natural gas for specific end-use applications will be explored.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Table 1
2007 Regulatory Budget

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 1
	RESIDENTIAL MARKET	Vol (10^6 m^3)	Number of Participants	Life	Program Costs ($)	Incremental Cost per Participant	5 Year Distribution Revenue ($m)	Life NPV ($m)	TRC ($m)	SCT ($m)
1	High Efficiency Furnace	6.49	3,174	18	108,000	800	3.70	2.31	22.95	25.02
2	ECM	0.33	5,000	18	-	550	0.12	0.19	(0.54)	(0.36
3	Mid Efficiency Furnace	0.30	123	18	19,850	400	0.17	0.11	1.11	1.21
4	Fireplace	1.77	5,303	12	170,690	700	0.68	0.61	(6.12)	(6.20
5	Grill/BBQ	0.07	1,477	12	20,200	250	0.03	0.01	(0.18)	(0.19
6	Range/Dryer/Front Load Axis Washer	1.26	12,966	12	30,300	300	0.48	0.49	0.03	0.20
7	Low Income (WH)-fuel switching	0.78	1,150	9	925,000	800	0.38	(0.56)	0.38	0.54
8	Interior Constr. Heat Res New Cons*	10.60	18,644	1	123,742	350	1.40	0.80	5.19	5.45
9	Interior Constr. Heat Small Comm*	0.37	107	1	17,916	350	0.02	0.00	0.35	0.36
10	Residential Fuel Switching (Water Heating)	1.03	1,518	9	358,000	600	0.47	(0.06)	1.79	1.99
11	Water Heating	0.99	2,500	9	49,100	600	0.39	0.26	1.49	1.68
12	Outdoor Living/Garage heating/Pool Heating	0.33	550	12	170,690	700	0.12	0.04	(1.11)	(1.30
13	EnergyLinkTM	8.00	22,933	12	1,036,300	466	3.04	2.06	1.30	1.93
		32.31	75,445		3,029,788		10.99	6.26	26.67	30.33
14							Less Overhead	(2.49)	(2.49)	(2.49
15							Net Benefits	3.77	24.18	27.84
	BUSINESS MARKET									
16	Multi - Family Housing	3.75	18	20	180,823	350,000	0.80	1.17	11.75	12.78
17	Forklift Conversion	1.26	139	15	40,600	15,000	0.26	0.33	5.53	5.66
18	Commercial Construction Heaters*	7.00	175	1	20,000	1,600	0.46	0.28	7.02	7.19
19	Institutional/Commercial/Industrial	0.52	1,000	20	20,000	1,000	0.15	0.24	1.52	1.66
20	Small Com'l Business Partners	1.24	55	15	36,702	2,000	0.32	0.38	5.20	5.55
21	Small Com'l Load Plus	1.96	700	15	87,264	2,500	0.48	0.60	6.46	6.94
22	Small Com'l Additions/NonComs	1.92	180	15	87,824	5,000	0.52	0.43	6.44	7.03
		17.65	2,267		473,213		2.99	3.42	43.92	46.80
23							Less Overhead	(1.68)	(1.68)	(1.68
24							Net Benefits	1.74	42.24	45.13
25							**Total Net Benefits**	**5.51**	**66.42**	**72.97**

* Volumes are fully effective in the 1st year; distribution revenue, NPV, TRC and SCT based on 1 year only.

Witnesses: S. Clinesmith
P. Green
N. Ryckman
P. Squires

Priority of energy issues

When asked to assign a priority to a series of specific energy issues (on a scale of 1 to 10, where 10 is highest priority), stakeholders again give the highest rating to the issue of electricity supply. Other issues with high importance include electricity reliability, electricity infrastructure and policy stability. Natural gas supply, natural gas pricing and competition are given a lower priority.

Since 2005, the importance assigned to the issue of conservation has increased slightly; electricity pricing and natural gas pricing receive somewhat lower ratings now than in 2005.

Priority of energy issues

Please rate the priority of the following energy issues on a ten-point scale, where a score of 1 means the issue is the lowest priority and 10 means it is the highest priority.

	2006	2005
	Mean	Mean
Electricity supply	9.1	9.1
Electricity reliability	8.6	8.4
Electricity infrastructure	8.5	–
Policy stability	8.4	8.2
Electricity pricing	7.6	8.0
Investor confidence in the energy sector	7.4	7.6
Public confidence in the energy sector	7.3	7.3
Energy conservation	6.9	6.5
Natural gas supply	6.4	6.2
Natural gas pricing	6.0	6.6
Competition	5.3	5.5

FUEL SWITCHING AND ENBRIDGE GAS DISTRIBUTION

FOR ENBRIDGE GAS LIMITED

By
SeeLine Group Inc.
416-703-8695

February 2006

1.0 INTRODUCTION

As part of its support for Enbridge Gas Distribution (EGD) marketing efforts, SeeLine Group Inc (SLG) undertook an assessment of the proposed electric fuel switching program. The focus of the analysis was the determination of the Total Resource Cost Test (TRC) for the proposed electricity to gas fuel switching technologies. These technologies include space heating, water heating, cooking and clothes drying.

2.0 APPROACH

SLG conducted two analyses for this study. The first analysis used technology and program input assumptions provided by Enbridge (Fuel_Switching_Option 2 Master_may25.xls). The second analysis used some of the input assumptions supplied by Enbridge; however, electricity usage data for clothes dryers, ranges and water heaters, was supplemented by information currently available from the Ontario Energy Board.

Both TRC analyses were conducted using the benefit and cost definitions and structures as approved by the Ontario Energy Board where the cost is defined as the increased societal cost of natural gas (as expressed by the avoided costs), the incremental equipment cost and the associated utility program support costs. The benefits are the avoided resource costs associated with a reduction in electricity use.

The TRC assessments were conducted using SLG's SeeTool™ TRC calculator. This tool and approach replicates both the DSStrategist™ model used in the past by Enbridge and the common approach used by electric utilities in Ontario currently undertaking Conservation and Demand Management TRC planning and analysis exercises.

Electricity avoided costs used in the analysis are those provided by the Ontario Energy Board. Avoided costs are expressed in eight costing periods for energy (winter peak, winter mid-peak, winter off-peak, summer peak, summer mid-peak, summer off peak, shoulder peak and shoulder off peak) and one (summer) for peak (demand). As such, all electricity savings values must also be defined in the same manner.

In absence of gas costs used to evaluate system expansion projects, the company's DSM avoided gas costs were used for this analysis. These costs were used for the EBO 2005-0001 rate case evidence and provide a good proxy for examining fuel switching programs.

2.0 RESULTS

Results from the first phase of this analysis are summarized in the tables below. Table 1a provides a summary of the proposed fuel switching program using the lower equipment life values for each technology.

Table 1a. Summary of TRC Results using Enbridge Data and Lower Equipment Life Assumptions

Program Results with Lower Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (15 yrs)	$38,348,134	$ 49,310,597	$45,181,049	$29,497,987	$32,477,881	$ 194,815,647
Ranges (14 yrs)	$ 3,630,417	$ 4,594,486	$ 4,224,016	$ 2,831,876	$ 3,277,971	$ 18,558,766
Dryers (11 yrs)	$ 7,998,805	$ 10,638,713	$ 9,785,085	$ 6,255,385	$ 7,020,153	$ 41,698,142
Water Heaters (10 yrs)	$11,461,554	$ 35,878,424	$32,873,762	$21,615,245	$23,701,290	$ 125,530,276
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$58,381,187**	**$ 100,424,227**	**$92,065,920**	**$60,202,502**	**$66,479,306**	**$ 377,553,142**

* Marketing/Administration/Promotion Costs

Based on above results, the fuel switching program would provide positive net benefits for each year and technology as specified by the program assumptions. The total TRC net benefits for the full five years of the program are $377,553,142 (in 2006 dollars).

It should be noted that these and other TRC test results, do not include the $305,972,900 in incentive costs. These costs are merely transfer payments between the utility and the participant and therefore cancel each other out.

Table 1b. Summary of TRC Results using Enbridge Data and Higher Equipment Life Assumptions

Program Results with Higher Equipment Life Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010	Total
Furnaces (17 yrs)	$ 44,949,956	$ 57,878,105	$ 53,031,066	$ 34,576,213	$ 38,099,274	$ 228,534,613
Ranges (15 yrs)	$ 4,307,348	$ 5,541,070	$ 5,095,007	$ 3,362,696	$ 3,940,171	$ 22,246,293
Dryers (13 yrs)	$ 9,925,804	$ 13,315,623	$ 12,248,091	$ 7,765,907	$ 8,758,977	$ 52,014,403
Water Heaters (13 yrs)	$ 15,145,647	$ 47,437,924	$ 43,465,204	$ 28,566,563	$ 31,331,634	$ 165,946,972
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$ 71,271,032**	**$ 124,174,730**	**$ 113,841,376**	**$ 74,273,388**	**$ 82,132,066**	**$ 465,682,552**

* Marketing/Administration/Promotion Costs

As would be expected, the higher equipment life assumptions yield greater TRC net benefits as shown in Table 1b. This is largely due to the longer lifecycle of net benefits. Under this scenario the fuel switching program would result in a net benefit of $465,682,552 under the TRC test.

The second analysis in this study, examined TRC results for the fuel switching program using electricity and gas data supplied by the OEB for dryers, ranges and water heaters, supplemented with Enbridge data for furnaces. Results from this analysis are below in Table 2.

Table 2. Summary of TRC Results using OEB and Enbridge Data

Program Results with OEB Assumptions
Total Resource Net Benefits
(shown in 2006 $'s)

	2006	**2007**	**2008**	**2009**	**2010**	**Total**
Furnaces (17 yrs)	$ 40,454,960	$ 52,090,295	$ 47,727,959	$ 43,730,950	$ 34,289,346	$ 218,293,510
Ranges (18 yrs)	$ 4,500,694	$ 5,784,007	$ 5,318,341	$ 4,872,953	$ 3,865,617	$ 24,341,613
Dryers (18 yrs)	$ (3,566,959)	$ (5,118,007)	$ (4,710,252)	$ (2,801,090)	$ (3,286,700)	$ (19,483,008)
Water Heaters (18 yrs)	$ 37,869,397	$ 48,467,826	$ 44,408,856	$ 32,885,153	$ 31,985,734	$ 195,616,965
Program Costs*	$ (3,059,729)					$ (3,059,729)
Total	**$ 76,200,369**	**$ 101,226,128**	**$ 92,746,912**	**$ 78,689,975**	**$ 66,856,007**	**$ 415,719,391**

* Marketing/Administration/Promotion Costs

Once again, results indicate overall that the program provides positive net benefits under the TRC. However, dryers are not costs effective using data provided by the OEB. This is largely due to higher gas consumption and lower electricity savings assumptions.

The following tables provide a more detailed summary of results for each scenario.

Table 3. Enbridge Gas Fuel Switching Program with Enbridge's Gas and Electricity Data

Summary of Fuel Switching Opportunities Using Enbridge Data
Total Resource Cost Test Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010
Furnaces (15 Yrs)					
Existing Homes	$ 23,205,868	$ 35,436,429	$ 32,468,783	$ 17,850,318	$ 21,805,654
System Expansion	$ 5,325,549	$ 4,879,557	$ 4,470,916	$ 4,096,496	$ 3,753,432
Infill	$ 5,917,276	$ 5,421,730	$ 4,967,684	$ 4,551,662	$ 4,170,480
New Homes	$ 3,899,441	$ 3,572,879	$ 3,273,666	$ 2,999,511	$ 2,748,315
Total	**$ 38,348,134**	**$ 49,310,597**	**$ 45,181,049**	**$ 29,497,987**	**$ 32,477,881**
Furnaces (17 Yrs)					
Existing Homes	$ 27,329,303	$ 41,733,105	$ 38,238,139	$ 21,022,129	$ 25,680,286
System Expansion	$ 6,271,842	$ 5,746,603	$ 5,265,350	$ 4,824,400	$ 4,420,377
Infill	$ 6,968,713	$ 6,385,114	$ 5,850,388	$ 5,360,444	$ 4,911,530
New Homes	$ 4,380,098	$ 4,013,283	$ 3,677,186	$ 3,369,240	$ 3,087,081
Total	**$ 44,949,956**	**$ 57,878,105**	**$ 53,031,066**	**$ 34,576,213**	**$ 38,099,274**
Ranges (14 Yrs)					
Existing Homes	$ 2,050,461	$ 3,131,240	$ 2,869,013	$ 1,577,247	$ 2,116,409
System Expansion	$ 104,876	$ 103,485	$ 101,591	$ 99,289	$ 96,660
Infill	$ 116,529	$ 114,983	$ 112,879	$ 110,321	$ 107,400
New Homes	$ 1,358,551	$ 1,244,778	$ 1,140,533	$ 1,045,018	$ 957,503
Total	**$ 3,630,417**	**$ 4,594,486**	**$ 4,224,016**	**$ 2,831,876**	**$ 3,277,971**
Ranges (15 Yrs)					
Existing Homes	$ 2,578,143	$ 3,937,057	$ 3,607,346	$ 1,983,148	$ 2,661,061
System Expansion	$ 131,866	$ 130,117	$ 127,736	$ 124,841	$ 121,535
Infill	$ 146,517	$ 144,574	$ 141,928	$ 138,712	$ 135,039
New Homes	$ 1,450,823	$ 1,329,323	$ 1,217,998	$ 1,115,996	$ 1,022,536
Total	**$ 4,307,348**	**$ 5,541,070**	**$ 5,095,007**	**$ 3,362,696**	**$ 3,940,171**
Dryers ([illegible] Yrs)					
Existing Homes	$ 5,351,752	$ 8,172,610	$ 7,488,190	$ 4,116,652	$ 5,029,200
System Expansion	$ 336,897	$ 327,976	$ 318,187	$ 307,737	$ 296,805
Infill	$ 374,330	$ 364,418	$ 353,541	$ 341,930	$ 329,784
New Homes	$ 1,935,825	$ 1,773,709	$ 1,625,168	$ 1,489,067	$ 1,364,364
Total	**$ 7,998,805**	**$ 10,638,713**	**$ 9,785,086**	**$ 6,255,385**	**$ 7,020,153**
Dryers ([illegible] Yrs)					
Existing Homes	$ 6,825,264	$ 10,422,797	$ 9,549,933	$ 5,250,100	$ 6,413,903
System Expansion	$ 429,656	$ 418,279	$ 405,794	$ 392,467	$ 378,525
Infill	$ 477,396	$ 464,754	$ 450,882	$ 436,074	$ 420,584
New Homes	$ 2,193,489	$ 2,009,794	$ 1,841,482	$ 1,687,266	$ 1,545,965
Total	**$ 9,925,804**	**$ 13,315,623**	**$ 12,248,091**	**$ 7,765,907**	**$ 8,758,977**
Water Heaters (10 Yrs)					
Existing Homes	$ 7,108,810	$ 25,328,823	$ 23,207,644	$ 12,758,622	$ 15,586,371
System Expansion	$ 1,631,411	$ 4,099,989	$ 3,756,633	$ 3,442,031	$ 3,153,776
Infill	$ 1,812,679	$ 4,555,544	$ 4,174,037	$ 3,824,479	$ 3,504,196
New Homes	$ 908,653	$ 1,894,069	$ 1,735,449	$ 1,590,112	$ 1,456,947
Total	**$ 11,461,554**	**$ 35,878,424**	**$ 32,873,762**	**$ 21,615,245**	**$ 23,701,290**
Water Heaters (13 Yrs)					
Existing Homes	$ 9,409,859	$ 33,527,503	$ 30,719,720	$ 16,888,457	$ 20,631,519
System Expansion	$ 2,159,482	$ 5,427,114	$ 4,972,617	$ 4,556,182	$ 4,174,621
Infill	$ 2,399,425	$ 6,030,126	$ 5,525,130	$ 5,062,424	$ 4,638,468
New Homes	$ 1,176,880	$ 2,453,181	$ 2,247,738	$ 2,059,500	$ 1,887,026
Total	**$ 15,145,647**	**$ 47,437,924**	**$ 43,465,204**	**$ 28,566,663**	**$ 31,331,634**

As shown in Table 3. each technology scenario would be cost effective from a TRC perspective.

Table 4. Enbridge Gas Fuel Switching Program with both Enbridge and OEB's Gas and Electricity Data

Summary of Fuel Switching Opportunities Using OEB Data
Total Resource Cost Test Net Benefits
(shown in 2006 $'s)

	2006	2007	2008	2009	2010
Furnaces (15 Yrs)					
Existing Homes	$ 20,885,281	$ 31,892,786	$ 29,221,904	$ 16,065,286	$ 19,625,088
System Expansion	$ 4,792,994	$ 4,391,602	$ 4,023,824	$ 3,686,846	$ 3,378,089
Infill	$ 5,325,549	$ 4,879,557	$ 4,470,916	$ 4,096,496	$ 3,753,432
New Homes	$ 3,509,497	$ 3,215,592	$ 2,946,300	$ 2,699,560	$ 2,473,484
Total	**$ 34,513,320**	**$ 44,379,537**	**$ 40,662,944**	**$ 26,548,189**	**$ 29,230,093**
Furnaces (17 Yrs)					
Existing Homes	$ 24,596,373	$ 37,559,794	$ 34,414,325	$ 31,532,275	$ 23,112,257
System Expansion	$ 5,644,658	$ 5,171,942	$ 4,738,815	$ 4,341,960	$ 3,978,339
Infill	$ 6,271,842	$ 5,746,603	$ 5,265,350	$ 4,824,400	$ 4,420,377
New Homes	$ 3,942,088	$ 3,611,955	$ 3,309,470	$ 3,032,316	$ 2,778,373
Total	**$ 40,454,960**	**$ 52,090,295**	**$ 47,727,959**	**$ 43,730,950**	**$ 34,289,346**
Ranges (18 Yrs)					
Existing Homes	$ 2,684,511	$ 4,099,491	$ 3,756,176	$ 3,441,613	$ 2,522,714
System Expansion	$ 168,992	$ 164,517	$ 159,607	$ 146,240	$ 148,881
Infill	$ 187,769	$ 182,797	$ 177,341	$ 162,489	$ 165,424
New Homes	$ 1,459,423	$ 1,337,202	$ 1,225,217	$ 1,122,611	$ 1,028,597
Total	**$ 4,500,694**	**$ 5,784,007**	**$ 5,318,341**	**$ 4,872,953**	**$ 3,865,617**
Dryers (18 Yrs)					
Existing Homes	$ (2,990,985)	$ (4,567,505)	$ (4,184,996)	$ (2,300,712)	$ (2,810,717)
System Expansion	$ (152,982)	$ (150,952)	$ (148,190)	$ (144,832)	$ (140,997)
Infill	$ (169,979)	$ (167,725)	$ (164,656)	$ (160,924)	$ (156,663)
New Homes	$ (253,014)	$ (231,825)	$ (212,411)	$ (194,622)	$ (178,323)
Total	**$ (3,566,959)**	**$ (5,118,007)**	**$ (4,710,252)**	**$ (2,801,090)**	**$ (3,286,700)**
Water Heaters (16 Yrs)					
Existing Homes	$ 22,543,286	$ 34,425,210	$ 31,542,249	$ 24,771,584	$ 21,183,933
System Expansion	$ 6,081,746	$ 5,572,426	$ 5,105,760	$ 1,851,777	$ 4,286,398
Infill	$ 6,757,495	$ 6,191,585	$ 5,673,066	$ 2,057,530	$ 4,762,664
New Homes	$ 2,486,869	$ 2,278,605	$ 2,087,781	$ 4,204,261	$ 1,752,738
Total	**$ 37,869,397**	**$ 48,467,826**	**$ 44,408,856**	**$ 32,885,153**	**$ 31,985,734**

As shown in Table 4, all technologies remain cost effective from a TRC perspective using OEB data with the exception of dryers. Based on the savings and cost data outlined in the OEB measures list, this measure would results in a negative TRC for each year in the five year plan.

3.0 CONCLUSIONS

The Ontario Energy Board has provided a list of prescriptive savings for many typical residential and commercial technologies. Where appropriate, these values are recommended for use by Enbridge.

The following table provides a summary of the saving and cost inputs as supplied by Enbridge and those provided by the OEB measure list.

Table 5. Comparison of Enbridge Data vs. OEB Data

	Enbridge	OEB
Furnaces		
Gas Consumption	1800 m3	n/a
kW Savings	17100 kW	n/a
kWh Savings	17000 kWh	n/a
Equipment Life	15 and 17 Years	n/a
Freeriders	0%	n/a
Incremental Equipment Costs	$1,750 (new) and $3,243 (existing)	n/a
Ranges		
Gas Consumption	100 m3	81 m3
kW Savings	0.5 kW	0 kW
kWh Savings	880 kWh	735 kWh
Equipment Life	14 and 15	18
Freeriders	0%	10%
Incremental Equipment Costs	$225 (new) and $475 (existing)	$400 (new)
Dryers		
Gas Consumption	100 m3	112 m3
kW Savings	.165 kW	0.04 kW
kWh Savings	1200 kWh	916 kWh
Equipment Life	11 and 13	18
Freeriders	0%	10%
Incremental Equipment Costs	$25 (new) and $275 (existing)	$0 (new)
Water Heaters		
Gas Consumption	728 m3	680 m3
kW Savings	1.14 kW	0.357 kW
kWh Savings	4,950 kWh	5,000 kWh
Equipment Life	10 and 13	18
Freeriders	0%	10%
Incremental Equipment Costs	$454 (new) and $545 (existing)	$600 (new)

The impact on TRC net benefits is significant in the case of dryers when using the OEB data; however under each scenario (low equipment life assumptions, higher equipment life assumptions and OEB data) the overall five year fuel switching program provides positive TRC net benefits.

It should also be noted that the forecast of avoided gas and electricity costs play a significant role in the cost effectiveness of fuel switching programs. Based on the most current forecast of gas and electricity, the saving benefits from electricity consumption far outweigh the increases in gas consumption. However, if either energy forecasts were to change, another examination of TRC net benefits for fuel switching opportunities would be recommended.

EB-2006-0021
K 3.2 / T 9

Written Submission

Enbridge Gas Distribution to the Ontario Power Authority in the matter of the province's energy supply mix August 26, 2005

Introduction: Enbridge Gas Distribution ("Enbridge") is pleased to provide this response to the Call for Written Submissions issued by the Ontario Power Authority in the matter of the province's energy supply mix. The following considerations reflect Enbridge's 157-year history of anticipating and adapting to changing energy circumstances in Ontario, and meeting the changing needs of generations of customers.

Natural gas - Part of a diverse energy portfolio: Ontario's natural gas sector is wellpositioned to play its part in realizing the government's stated goal of a diverse supply of competitively priced power within a conservation culture:

- *Sufficient supply:* There will be enough natural gas supply to meet future needs. Natural Resources Canada has calculated total remaining natural gas reserves in North America alone at 75 times current consumption levels. In addition, significant additional reserves have been and are being identified.

- *Fair and reasonable prices:* Natural gas is and will remain an economic energy choice. Based on the experience of Enbridge's own customers in recent years, natural gas has been on average about 39% less expensive than electricity and 20% less expensive than oil.

- *Environmental benefits:* Environment Canada has noted that natural gas-flred power generation emits the lowest level of greenhouse gases among all fossil fuels. In addition, an independent study released by the Ministry of Energy in April 2005 concluded that a combination of nuclear and natural gas- generated electricity was the lowest-cost energy scenario in terms of money, public health and the environment.

- *Conservation culture:* The natural gas sector has initiated a number of energy efficiency programs to help customers reduce the amount of natural gas they use. Programs implemented by Enbridge between 1995 and 2004 alone reduced consumption by the equivalent of the gas used by 620,000 homes in one year. Those same programs reduced carbon dioxide emissions by the equivalent of removing 750,000 cars from the road for one year.

- *Advancing stated public policy objectives:* As noted above, natural gas can advance the Ministry's stated desire for diversity of supply. It also advances the fmdings of an Ontario Energy Board ("OEB") report issued in March 2005, which recognized the important and growing role of natural gas and natUral gas infrastructure in the province's energy system.

Fuel switching - The focus of this submission: There are a number of ways in which natural gas can contribute to the achievement of the province's stated energy needs and objectives. One 'way is through large scale electricity generation. Another is through distributed energy. Still another is through energy efficiency models that provide demand side management and other programs tailored to particular classes of customers.

The focus of this submission, however, is on another aspect of the natural gas component of a diverse energy mix. This aspect - fuel switching - entails the switching of customers from electric appliances to natural gas appliances that can perform the same chores, often in a more effective and cost-efficient way.

Fuel switching - The plan and the benefits: The remainder of this submission discusses a five-year plan for the switching of 1,043,425 furnaces, water heaters, ranges and dryers from electricity to natural gas. Under this initiative, the benefits to Ontario would include:

- *Reduced electricity demand:* Peak load electricity demand would be reduced by 1,490 megawatts.
- *Avoided generation costs:* The move to natural gas-fired appliances would realize avoided electricity generation costs of $1.146 billion.
- *Decreased greenhouse gas emissions:* The switch from electric to natural gas appliances would lower greenhouse gas emissions by 2.5 million tonnes.

Fuel switching - The potential for quick 'wins': One of the key attributes of the fuel switching initiative is the speed with which the benefits could be realized. This is due, in part, to the fact that the natural gas infrastructure and technology to implement such a program are already in place. There follow three areas or quick 'wins' that demonstrate the benefits that can be achieved for Ontario in short order, using existing technology, and building on current or reinforced infrastructure.

- *Space heating:* Electrical residential space heating can account for up to 60% of residential electricity use. Switching the space heating source from electricity to natural gas furnaces could save $1.1 billion in avoided generation costs.
- *Water heating:* Heating water electrically can total up to 20% of residential electricity use. Switching to natural gas tankless water heaters can increase energy efficiency and lower customer costs
- *Helping low income residents:* Approximately 14% of Ontario residents live at or near the poverty line. More than 50% of them use electric water heaters, which cost more to operate than natural gas heaters. Thus, people who can least afford it are paying more to heat their water than they have to. Switching their water heaters from electricity to natural gas has the potential to save this group some $146 million in avoided generation costs.

Fuel switching. The role of incentlres: One way to encourage the implementation of arry fuel switcrung initiative is to make the prospect attractive to customers. Here, as elsewhere in the economy, retail prices can influence consumer choices and buying decisions. The cost of purchasing new natural gas appliances, before the end ofthe useful life of existing electricity appliance stock, can be an impediment to change with many . customers. This fact alone can deter consumers from pursuing the natural gas option, even though they can realize significant cost savings over the life of those natural gas appliances.

One way to encourage consumers to choose the natural gas option, and to realize the potential benefits for the province, is through the use of direct-to-ratepayer incentives for purchasing natural gas appliances. Such incentives could be provided in one of two ways. The frrst is by the provincial government itself. The second is through the regulatory process in which local utilities would factor such incentives into their rate structure, build cost recovery plans into their rate submissions, and seek approval of those submissions through the OEB in the normal course.

Either way, if direct-to-ratepayer incentives were provided for 50% of the purchase price of switching to natural gas appliances, and as the Fuel Switching - Summary Results document appended to this submission indicate, Ontario would still realize net avoided generation costs of $617 million unger the proposed five-year fuel switching program.

Fuel switching· Other considerations: Enbridge recognizes that other considerations are associated with the proposed fuel switching initiative. One is that the cost of the related system expansion would fall within natural gas utility rates. Another is that the demand for natural gas would increase. Analysis suggests, however, that the increased use would equal just 0.2% of total North American demand. A third factor is the proposed five-year timetable itself. Enbridge believes that this schedule, while aggressive, is achievable using current technology and building on current infrastructure._

In conclusion - Natural gas, fuel switching, and the benefits to Ontario: By way of summary, and in support of its proposed five-year fuel switching initiative from electric to natural gas appliances, Enbridge Gas Distribution submits that:

- Natural gas can do its part: Natural gas is well-equipped to playa significant role within Ontario's changing energy mix. It is plentiful, economical, and environmentally sound.

- Fuel switching is a viable and achievable initiative: Fuel switching from electric to natural gas appliances - an initiative that is being pursued elsewherecan be achieved at low risk through existing infrastructure and technology.

- Ontario will benefit: The fuel switching initiative will, among other things, address the government's stated policy objectives, reduce electricity demand, avoid generation costs and lower greenhouse gas emissions.

Fuel Switching- Summary Results

	Over 5 years
Megawatts Saved (Diversified Demand)	**1,490**
Net GHG Emissions Reduced	**2.5 million tonnes**
Cost of 1,490 MW NG Fired Generation	**$1.146 billion**
Incentive Cost (@ 50% of replacement)	**$0.529 billion**
Avoided Generation Cost	**$0.617 billion**
Ratio of NG Fired Generation Costs to Incentive	**2to 1**
Total Electric Appliances switched	**1,043,425**
Furnaces	**114,875**
Water Heaters	**279,200**
Ranges Dryers	**323,000**
	326,350

Market Transformation Assumptions

Enbridge Gas Distribution Inc.			Market Penetration				
		SYears		Existinl! Home		New Homes	
Residential Customers	1,525,000		**Aooliance**	**Current**	**Proposed**	**Current**	**Proposed**
New Home additions	40,000	200,000	**Furnaces**	90%	93%	98%	100%
System Expansion/year	4,500	22,500	**Water Heaters**	86%	93%	91%	96%
Infill Customers/year	5,000	25,000	**Ranaes**	24%	34%	24%	34%
			Dryers	30%	46%	30%	40%

System Expansion	35% electricity /65% oil
Infill Customers	35% electricity /65% oil
Heatinl't only	3.5% electricity /65% oil

Vnion Gas			Market Penetration				
		S Years		Existilll Home		New Homes	
Residential Customers	1,200,000		**Aooliance**	**Current**	**ProPosed**	**Current**	**Proposed**
~ ew Home additions	20,000	100,000	**Furnaces**	92%	95%	100%	100%
SYStem Expansion/year	1,000	5,000	**Water Heaters**	85%	92%	86%	96%
Infill Customers/year	4,000	20,000	**Ran2es**	19%	29%	19%	29%
			Dryers	21%	31%	21%	31%

System Expansion	50% electricity / 50% oil
Infill Customers	50% electricity / 50% oil
Heatin~ only	50% electricity / 50% oil

- Incentives to utilities will be required for market transformation and should be paid annually.

Utilities should submit market transformation proposals as part of the filing in the first year of the multi-year plan. Proposals should outline objectives, target market, and budget.

Upon each subsequent multi-year plan submission, the progress on Market Transformation would be reported and the Utility would decide to continue to pursue a market transformation project or to discontinue the activity.

As stated, an incentive for Market Transformation programs is essential. Market Transformation programs must compete for Utility resources in the same way as any other program. Given the multi-year nature and difficulty of measurement in each year, Union and Enbridge have developed an approach to calculating the incentive for Market Transformation programs that is outlined in the DSM Handbook filed in Tab 3.

FUEL SWITCHING

It is Union's view that fuel switching from other fuels to natural gas should not be considered a DSM program as it does not reduce natural gas consumption. Instead, fuel switching should be run as a separate program by the utility.

Electricity conservation in Ontario has been largely driven by a need to address the existing and expected supply imbalance for electricity. Peak electricity demand exceeds Ontario's power generation capacity and increases the need for expensive electricity imports. Additionally, Ontario has committed to phasing out coal fired generation causing further pressure on the supply shortfall.

While new generation is clearly required, Ontario must also consider conservation as an essential means to address the issue. The ability to install new power generation capacity is a longer-term initiative. Fuel switching from electricity to natural gas is an integral part of the solution to the electricity supply imbalance in the near term.

The Board can send a strong message and set a positive policy direction by approving a specific fuel switching program for natural gas utilities. Union proposes that a separate fuel switching program be approved by the Board. The program would set budgets and report results in a similar fashion to DSM programs. The budget for fuel switching should be set in the same way as the DSM budget. A maximum budget of 2% of distribution revenue should be established in rates for the duration of the fuel switching plan. The utility would establish an actual budget in the test year and would apply the same rules to the budget and actual spending as are applied in the DSM framework. That is, Union would build the 2% budget into rates and would return to the ratepayer any unspent portion of the budget through a deferral account.

It is important to note that fuel switching is a complex issue and requires a coordinated approach among natural gas utilities, government, government agencies such as the OPA and electric LDCs. Union would seek partnerships in the delivery of fuel switching programs in order to ensure the resources are adequate and the focus is results based. Union would submit to the Board in the test year a fuel switching plan, similar to the DSM plan, establishing target markets, input assumptions and program descriptions. Results would be reported on an annual basis in a similar fashion to the annual DSM results reporting. Given the inherent nature of fuel switching programs, there would be no need for incentive mechanisms (i.e., SSM) or revenue adjustments (i.e., LRAM).

SUMMARY

Union's proposal outlines a framework that will meet the objectives and principles outlined by both Union and Enbridge in the joint submission in Tab 1.

Union emphasizes that it is important to establish a framework that creates certainty around the "rules" of DSM over not just one DSM Plan but over many DSM Plans. It is not productive to continually revisit the same items in each successive plan filing.

It is also essential in considering a framework to realize that the key framework items do not work discretely, but as interdependent items. Changing one can only be done by considering the appropriate changes to the other framework items in order to ensure that the goals and objectives of DSM in Ontario are maintained and not compromised.

DIRECT ENERGY MARKETING LIMITED INTERROGATORY #1

INTERROGATORY

Issue Number: 7.5
Issue: Is the Applicant's proposal of open bill access appropriate and consistent with the Board's direction in RP-2005-0001?

What are the utility and ratepayer advantages of having open bill access in relation to the Enbridge Gas Distribution Inc. ("EGD") bill? What was the impetus, even before Direct Energy obtained access to the bill, for having services on the bill and does that impetus still exist?

RESPONSE

There are clear advantages to all parties, including the customer, of having open bill access. Allowing customers to pay for the rental or financing of their natural gas appliance product via the utility bill helps to overcome a significant first cost barrier. This barrier relates to the higher capital cost outlay of natural gas equipment versus competing fuel-type equipment. Utility bill access provides a valuable service for customers by allowing them to acquire natural gas appliances with more manageable payments and with improved convenience.

By overcoming this market barrier, open bill access assists the Company in meeting key objectives to maintain and increase the growth of natural gas throughput and to provide additional DSM opportunities. Throughput growth ensures the long term sustainability of the Company's assets, while reducing rates for customers. Historically, allowing customers to rent and finance natural gas appliances on their utility bill was a major impetus in facilitating the market place along with a focused delivery channel even before Direct Energy obtained access to the bill. It enabled the market share for natural gas water heaters to increase from less than 50% in 1958 – the start of the water heater rental program to 89% in 2000.

Witnesses: P. Green
K. Lakatos-Hayward
S. McGill

Table 1

Impact on Distribution Revenue from Declining Water Heater Market Share

Water Heater Load (m3)		640
Marginal Distribution Revenue/m3 (2006 rates)	$	0.09
Annual Distribution Revenue / Water Heater	$	58.13
Number of Water Heater Customers		1,671,317.00
Impact on Distribution Revenue from 1% decrease in Market Penetration	$	(971,556.63)
Impact on Distribution Revenue from 5% decrease in Market Penetration	$	(4,857,783.14)
Impact on Distribution Revenue from 10% decrease in Market Penetration	$	(9,715,566.28)
Impact on Distribution Revenue from 20% decrease in Market Penetration	$	(19,431,132.56)

Table 1 shows the impact on distribution revenue from declining water heater market share. Over the past 5 years penetration levels have decreased from 89% to 86%, necessitating a higher revenue requirement in the order of $3.8 million. Penetration rates of other natural gas appliance products have also stagnated since 2002, coincident with the closure of major retail outlets specializing in natural gas products.

One benefit of Open Bill Access, therefore, is to increase the penetration of natural gas appliance products which improves overall distribution revenues and revenue requirement for ratepayers and the Company.

Open Bill Access also has a direct ratepayer benefit by lowering the forecast of O&M costs. This benefit amount is being revised as part of the 2007 draft interim solution which is anticipated to be tabled with the open bill consultative in mid-November for their consideration and input. As additional third parties transact on the bill, it is anticipated that this amount would increase over time. In addition, any net earnings from open bill access are proposed to be shared 50:50 with ratepayers, providing an additional benefit.

Witnesses: P. Green
K. Lakatos-Hayward
S. McGill

Schedule "A"
Potential Promotional Offerings*

Category	Natural Gas Elements	Complementary Elements
1. **Heating, Ventilation and Air Conditioning Equipment**	➢ Furnaces ➢ Water Heaters (Purchase or Rental) ➢ Boilers and Hydronics ➢ In Floor Radiant Heating ➢ Fireplaces	➢ Air Conditioners ➢ Indoor Air Quality Equipment
2. **HVAC Ancillary Equipment**		➢ HEPA Filters ➢ HRVs, EPVs ➢ Humidifiers, Electronic Air Cleaners ➢ Thermostats (Programmable)
3. **Service Programs**	➢ Heating and Air Conditioning Maintenance Programs. ➢ Heating and Air Conditioning Service / Protection Plans ➢ Insurance Programs – Lifestyle Products ➢ (e.g. Ranges, Dryers, Barbecues, Patio Heaters, Campfires).	
4. **Retail "White Goods"**	➢ Ranges ➢ Dryers ➢ Barbecues ➢ Pool Heaters ➢ Campfires ➢ Patio Heaters	
5. **Demand Side Management (DSM) Programs and Energy Messages**	➢ Programs and Services ➢ Energy Efficiency Efforts	
6. **Electric Contract Demand Management (CDM) Programs and Energy Messages**		➢ Programs and Services ➢ Energy Efficiency Efforts
7. **ENERGY STAR for New Homes and natural gas appliances**	➢ Builder New Home category promoted homes and sites with Energy Star labelling with natural gas appliances	

* The products and services set out in the table above are intended to provide general guidelines only. Notwithstanding anything to the contrary set forth elsewhere herein, Enbridge Gas Distribution reserves the right to, at any time, in its sole and absolute discretion, reject any proposed promotion. The Company will not provide the Service in relation to promotion of any natural gas commodity product offerings, nor in relation to promotions of products or services that compete with natural gas. The Company may allow for promotion of bundled products and services where the primary focus of such promotion is on natural gas, energy appliance and complementary products or energy efficiency.

K6.5

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> "Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility's residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K6.5
DATE February 5 2007
pages 32 & 33 from EB-2006-0021
08/05

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

Ontario Energy Board **Commission de l'Énergie de l'Ontario**

Ontario

EB-2006-0021

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF a generic proceeding initiated by the Ontario Energy Board to address a number of current and common issues related to demand side management activities for natural gas utilities.

BEFORE: Pamela Nowina
Presiding Member and Vice Chair

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION WITH REASONS

August 25, 2006

EXECUTIVE SUMMARY

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, Union Gas Limited ("Union") and Enbridge Gas Distribution Inc, ("EGD") have been filing DSM plans in response to the directives of the Board in the EBO 169-III Report.

In the Board's EB-2005-0001 decision dealing with EGD's 2006 rates, the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities – this decision. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act. The Board's findings in this decision, therefore, are orders of the Board pursuant to section 36 of the Act.

At the beginning of the oral hearing the Board was presented several documents which segmented the issues list into four categories. The categories consisted of a list of completely settled issues, a list of partially settled issues to which most intervenors and the utilities agreed, a list of partially settled issues to which all intervenors agreed with the exception of the utilities, and, a list of completely unsettled issues. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The Board's decision deals with a large number of issues relating to DSM. Generally, a rules-based and framework approach has been established where appropriate and practical. Below is a list of the broader matters that have been decided.

- A three-year term for the first DSM plan
- Processes for adjustments during the term of the plan
- Formulaic approaches for DSM targets, budgets, and utility incentives
- Determination of how costs should be allocated to rate classes
- A framework for determining savings
- A framework and process for evaluation and audit
- The role of the gas utilities in electric Conservation and Demand Management activities and initiatives

The Board will issue a Procedural Order to commence the next phase dealing with the determination of the input assumptions after which the gas utilities can file their respective three-year DSM plans.

DECISION –PHASE 1

CHAPTER 1 - INTRODUCTION

The Ontario Energy Board (the "Board") determined the original regulatory framework for gas utility sponsored Demand Side Management ("DSM") programs through guidelines established in its EBO 169-III Report of the Board dated July 23, 1993. DSM programs are programs which assist utility customers in reducing their natural gas consumption. Since 1995, the gas utilities have filed DSM plans in response to the directives of the Board in the EBO 169-III Report.

The EBO 169-III Report provided guidelines to assist the utilities in the development and implementation of their respective DSM plans. Although the objectives and principles have evolved somewhat over the years to reflect changing market and industry conditions, they remain essentially unchanged. These DSM plans formed part of the gas utilities rate cases and were reviewed annually.

Over the past decade there have been occasions where rules for DSM programs have been challenged, requiring further interpretation and scrutiny by the Board. In addition, the Board has been required to frequently make decisions on similar DSM issues for the two large gas utilities, Union Gas Limited ("Union") and Enbridge Gas Distribution ("EGD"), in separate proceedings. This has lead to increased regulatory burden for all parties and inconsistent practices by the two utilities. These concerns and the heightened focus on conservation and demand side management for the energy sector as a whole were the impetus for the Board to re-examine the DSM regime as it pertains to these two gas utilities through this generic proceeding.

In the Board's partial decision in EGD's 2006 rates application (EB-2005-0001 / EB-2005-0437), the Board announced its intention to convene a generic proceeding to address a number of current and common issues related to DSM activities for natural gas utilities. In the ensuing Notice of Hearing, the Board stated that the hearing will result in orders under section 36 of the Ontario Energy Board Act, 1998 (the "Act"). The Board's findings in this decision, therefore, should be considered orders pursuant to section 36 of the Act.

The Notice further stated that the following would be among the topics the Board would evaluate in making orders relating to the operation, evaluation and auditing DSM plans starting January 1, 2007:

- timing of the schedule for submitting and reviewing DSM plans,
- determination and use of planning assumptions for generic energy efficiency measures and custom projects,
- DSM budget as a percentage of utility annual revenue,
- structure and screening of programs including differentiating between market transformation, lost opportunity and enabling activities,
- structure and use of LRAM, SSM and DSMVA,
- process and content of program evaluations including the requirement for a third party audit process,
- length of plan, as well as updating the plan and reporting requirements,
- rules respecting free riders and attribution of energy savings, and
- the appropriateness of directing specific DSM measures to low-income consumers.

Other areas of focus will include the requirement for and role of the Consultative committee, filing requirements for the DSM plans and reporting requirements.

As the content of the topic list indicates, the intent of the proceeding was to streamline processes, harmonize practices where appropriate and re-examine the rules of DSM that had developed to date.

It was not the intent to revisit the general principles adopted and conclusions reached in the Report of the Board E.B.O. 169 III regarding the appropriateness of Demand Side Management being utilized by the Utilities in Integrated Resource Planning (IRP).

In the course of the proceeding, the Board received three settlement agreements. The first was a complete settlement on some of the issues. The other two were partial settlements.

The first partial settlement contained issues that were settled as between EGD and Union on the one hand, and most of the intervenors on the other. Some of the issues in this package dealt with the financial issues and this “financial package” was considered by the parties to be un-severable. That is to say that the parties to this partial agreement regarded each of the elements of the package to be crucial to the package as a whole. Were the Board to disapprove of any discrete element of the package, the package as a whole would be withdrawn, and each of the elements would have to be litigated.

The second partial settlement contained proposals that were agreed to by all intervenors but not the utilities.

The Board held an oral hearing that commenced on July 10, 2006. At the beginning of the oral hearing the Board accepted the completely settled issues as proposed. The oral hearing dealt with the issues contained in the two partial agreements, and other unsettled issues. The oral phase of the hearing, including argument, was concluded on July 28, 2006.

The non-utility parties to the hearing were Canadian Manufacturers & Exporters (“CME”), Consumers Council of Canada (“CCC”), Energy Probe, Green Energy Coalition (“GEC”), Industrial Gas Users Association (“IGUA”), London Property Management Association (“LPMA”), Low Income Energy Network (“LIEN”), Pollution Probe, School Energy Coalition (“SEC”) and Vulnerable Energy Consumer’s Coalition (“VECC”).

The full record of the proceeding is available at the Board’s offices. The Board has considered the full record but has summarized it in this decision to the extent necessary to provide context for its findings.

Chapter 2 deals with details of the completely settled issues. Chapter 3 addresses the issues contained in the “financial package”. Chapter 4 deals with the remaining issues. Chapter 5 deals with the issues respecting a common set of input assumptions, a common guide and with next steps. In that regard, this decision document is referred to as Phase 1. Appendix 1 contains details regarding some of the procedural aspects of the proceeding, including a list of parties’ representatives and witnesses.

CHAPTER 2 - THE SETTLEMENT PROPOSAL

A Settlement Proposal was filed with the Board on July 8, 2006 and was updated on July 11, 2006. The Board heard submissions from the parties and accepted the Settlement Proposal on July 11, 2006.

The Board acknowledges the effort of the participating parties to the Settlement Proposal and is pleased with the significant number of issues that were settled prior to the oral hearing.

Below are the completely settled issues which were accepted by the Board. To provide context to the balance of this decision, the Board sets out below the agreed upon phrasing of the settled issues. The numbering in brackets reflects the numbering that appeared on the Board's approved issues list for the proceeding.

Is a three year plan an appropriate term of a DSM plan? (Issue 1.2)

> "Parties agree that 3 years is an appropriate term for a multi-year DSM plan. Parties agree that the issue of whether and, if so, how a multi-year DSM plan should be aligned with a Utility's Incentive Regulation ("IR") period should be determined by the Board in the context of establishing the IR mechanism and rules, and cannot be determined in this proceeding in the absence of information on the structure and term of the IR regime adopted by the Board."

How are DSM parameters adjusted inside a multi-year rate making process? (Issue 1.6)

Parties referred this issue to completely settled Issue 1.2.

Should budgets, programs, targets, incentives and other plan components be established on an annual or multi-year basis? (Issue 1.8)

> “The approval of multi-year DSM plans will provide the utilities with the certainty of funding for programs which will have forecast life spans of more than one year. DSM plan components will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-plan plan.
>
> As this settlement provides that the budget, SSM mechanism, LRAM, and DSMVA are all developed and measured on an annual basis within a multi-year plan, it is appropriate that amounts be recorded in all DSM variance or deferral accounts on an annual basis (market transformation amounts may be an exception).”

How should the budget be allocated between customer classes in rates? (Issue 1.9)

> “Cost allocation in rates shall be on the same basis as budgeted DSM spending by customer class. This allocation should apply to both direct and indirect DSM program costs.”

Should the TRC [Total Resource Cost] test be the only test used to screen measures and/or programs for DSM plans? If no, what other tests should be used and how should these be applied? (Issue 2.1)

> “TRC shall be the only formal screen to determine whether a measure or program can be considered for inclusion in the portfolio. EBO 169-III identified numerous other considerations and tests that could be used to determine which measures and programs are actually selected for the portfolio in any given year, and those considerations and tests should continue to apply.”

How should free rider and savings input assumptions be determined? (Issue 3.1)

"Parties agree that input assumptions such as free rider rates, prescriptive measure savings assumptions, incremental equipment costs, measure lives and avoided costs (natural gas, electricity and water) shall be based on research utilizing the best available data at the time a multi-year plan or new program or significant new program design is developed. These assumptions shall be assessed for reasonableness prior to implementation of the plan or program and should be reviewed and updated on a regular basis during the plan period as part of each Utility's ongoing evaluation and audit processes."

What certainty is required that the assumptions are set for the duration of the DSM plan? (Issue 3.3)

"The time at which changes in assumptions become effective shall differ depending on the use to which the assumption is being put:

Program Design and Implementation. The Utilities agree to the principle that their DSM programs should be managed with regard to the best available information known to them from time to time. Normal commercial practice requires that a Company should react through changes to program design, implementation and/or mix, to material changes in base data as soon as is feasible given relevant operational considerations.

LRAM. Assumptions used will be best available at the time of an audit. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for LRAM purposes from the beginning of 2007 onwards until changed again.

SSM. Assumptions used from the beginning of any year will be those assumptions in existence in the immediately prior year, adjusted for any changes in the audit of that prior year. By way of example, if in June of 2008 the audit of the 2007 programs demonstrates a change in assumptions, that change shall apply for SSM purposes from the beginning of 2008 onwards until changed again."

What is the mechanism to determine if an input assumption needs to be reviewed or researched? (Issue 3.4)

"The Utility may of its own initiative or at the request of the Evaluation and Audit Committee ("EAC") commence a review of or research into assumptions."

How should the (LRAM) mechanism be structured? (Issue 4.2)

"The parties agree that the LRAM mechanism shall be calculated using the assumptions and savings estimates approved in the plan and adjusted for the audited Evaluation Report results.

For Union, the first year impact will be calculated as 50% of the annual volumetric impact multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

For EGD, the first year impact will be calculated on a monthly basis based on the volumetric impact of measures implemented in that month multiplied by the distribution rate for each of the rate classes that the volumetric variance occurred in.

Both of these processes for the Utilities reflect the status quo.

The LRAM account shall be cleared annually.

For purposes of clearing LRAM, input assumptions will be adjusted on an annual basis, as a result of the evaluation and audit work completed and shall apply from the beginning of the year being audited. See also Issue 3.3."

What evidence should be submitted to demonstrate that all conditions for clearance have been met? (Issue 4.3)

"Parties agree that the Utilities shall file an Audit report and any other backup needed to support the volumes used in the LRAM calculation. The Audit report will be prepared by an independent auditor to ensure accordance with Board approved rules. The auditor shall provide an opinion on the LRAM proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in Issue 9.3."

Is a third party audit required to verify LRAM calculation prior to clearance? (Issue 4.4)

"Yes, see issue 4.3 above."

How should LRAM costs be allocated between customer classes? (Issue 4.5)

"The LRAM shall be recovered in rates on the same basis as the lost revenues were experienced so that the LRAM ends up being a full true-up by rate class."

Should an incentive mechanism be in place? If yes, (Issue 5.1)

"Yes."

Is a third party audit required to verify year-end SSM calculation? And if required, what should be the audit principles, scope and timeline? (Issue 5.3)

"Parties agree that an independent auditor shall complete an evaluation audit with the purpose of verifying the claimed financial results and that the DSM shareholder incentive amounts (being the SSM and the incentive available in respect of market transformation programs) are calculated in accordance with the Board approved methodology. The audit shall provide an opinion on the DSM shareholder incentive amounts proposed and any amendment thereto. The remainder of the auditor's responsibilities are reflected in issue 9.3."

How should SSM costs be allocated between customer classes? (Issue 5.4)

"Parties agree that DSM shareholder incentive amounts shall be allocated to the rate classes in proportion to the net TRC benefits attributable to the respective rate classes."

What evidence is required to clear the DSMVA? (Issue 6.4)

"The utility shall clear DSMVA amounts, subject to review as a component of the DSM audit, to ensure compliance with the Board approved rules. The utility shall include the DSMVA as part of the audit described in issue 9.3. The utility may recover the amounts in the DSMVA from ratepayers provided it has achieved its annual TRC savings target on a pre-audited basis and the DSMVA funds were used to produce TRC savings in excess of that target on a pre-audited basis."

How should DSMVA balances be allocated between customer classes? (Issue 6.5)

"The Utilities shall allocate the DSMVA amounts in rates based on the Utility's DSM spending variance for that year versus budget, by customer class. The actual amount of the variance versus budget targeted to each customer class shall be allocated to that customer class for rate recovery purposes."

Should the DSM consultative be continued? If yes, (Issue 7.1)

"When required or useful, the utility will engage and seek advice from a variety of stakeholders and experts in the development and operation of its DSM program. As the utility is ultimately responsible and accountable for its actions, consultative activities shall be undertaken at its discretion. However, at a minimum, each utility will hold two consultative meetings annually. The purpose of the meetings will be to:

- Review annual results (the Evaluation Report will be sent to the Consultative annually for review) and select the Evaluation and Audit Committee ("EAC"). Three members will be selected using the current process used to select the Audit Sub-Committee; the fourth member will be the utility. In the current process, the members of the Consultative nominate individuals to stand on the committee. Then each member of the Consultative votes for the three members they would like on the committee. The three with the highest number of votes form the committee.

- Review the completed evaluation results.

The Utilities each acknowledge the principle that stakeholder consultation has proved valuable. They each intend to continue to take advantage of the input of the consultative as long as the consultative is adding value and the overall cost of the process is reasonable."

What role should the Consultative have in the DSM planning, design, approval and audit process? (Issue 7.2)

Settlement on this issue was referred to completely settled Issue 7.1.

How often should the Consultative and LDCs meet? (Issue 7.3)

"A utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement, subject to the requirement to meet twice annually set out under Issue 7.1 above. See Issue 7.5."

What is the appropriate amount that should be budgeted for Consultative and Sub-committee expenses? (Issue 7.4)

"The utility shall determine as part of the planning process, the appropriate amount to include in its overall DSM budget for stakeholder engagement, based on anticipated needs."

How should participation in the Consultative committee be determined? (Issue 7.5)

"The utility shall determine the stakeholders that it will engage based on the goals and objectives of the engagement. All intervenors in the Utility's most recent rate case shall be entitled to participate in the consultative meetings described in issue 7.1 above."

Should a percentage of the DSM budget be allocated to research? If yes, (Issue 8.1)

"Parties agree that the Utilities should conduct forward-looking DSM research. The appropriate level of budgets for research shall be determined by each Utility from time to time (depending upon need, market conditions, etc.) and each Utility should include a summary of its forecasted research in its multi-year DSM plan filed with the Board."

How should it be determined that research is required and when? (Issue 8.2)

"The utility shall determine the research needed to inform program assessment as part of its ongoing operational responsibilities and to ensure the long term viability of its DSM program. In making this determination, the Utility shall give due consideration to any recommendations of the EAC, the Auditor, and the consultative."

To reduce duplication, should certain research commitments be combined for both LDCs? (Issue 8.3)

"Each Utility shall be responsible and accountable for its research activities and expenses. The utility is expected to seek and leverage efforts with third parties where appropriate but it is recognized that unique circumstances and objectives may exist that preclude partnering in some instances."

How often should a DSM market potential study be conducted by the LDCs? (Issue 8.4)

"Market potential studies, or updates to an existing study, must be filed by each Utility together with its multi-year plan. The Utility may, in its discretion, do additional studies of market potential or updates during its plan."

What is the purpose of evaluation reports and what should they contain? (Issue 9.1)

"EGD and Union are accountable to the Board to develop and implement cost effective DSM programs including the monitoring and evaluation of results. In order to inform stakeholders on the activities and results of the DSM programs undertaken, the utility shall file annually, a clear and concise Evaluation Report that summarizes the savings achieved, budget spent and the evaluations conducted in support of those numbers.

It is the purpose of the evaluation and audit process to review all input assumptions related to the delivery of DSM over the period of the multi-year plan. To assist with that purpose, the parties propose the establishment of an EAC to engage stakeholders in the development of an evaluation plan and budget and to engage stakeholders in a review of the evaluation results as they become available over the term of the plan."

Is a third party audit of the evaluation report required? And if required, what should be the audit principles, scope and timeline? (Issue 9.3)

"The parties agree that a third party audit of the Evaluation Report is required. The auditor will be retained by the utility who determines the scope of the audit. It will be the role of the auditor to:

- Provide an opinion on the DSMVA, SSM and LRAM amounts proposed and any amendment thereto
- Verify the financial results in the Evaluation Report to the extent necessary to give that opinion
- Review the reasonableness of any input assumptions material to the provision of that opinion
- Recommend any forward looking evaluation work to be considered

The auditor shall be expected to take such actions by way of investigation, verification or otherwise as are necessary for the auditor to form their opinion. The auditor, although hired by the utility, must be independent and must ultimately serve to protect the interests of stakeholders."

Should there be an Audit Sub-committee with intervenor participation? And if yes, what role should the Audit Sub-committee have? (Issue 9.4)

"As described in Issue 9.3 above, parties agree that there should be an audit subcommittee entitled EAC. Participation in the EAC will be determined as set out in Issue 7.1.

The EAC will provide formal input into the evaluation plan. In regards to evaluation activities the EAC will continue to have an advisory role in the following:

- Consultation prior to the filing of the DSM plan on evaluation priorities for the next three years (or the duration of the multi-year plan). The utilities will, as part of their implementation plan, review all of the input assumptions over the course of each multi-year plan.
- Review and comment on evaluation study designs. Input on the research methodology used to determine the input assumptions.
- Reviewing the scope and results of evaluation work completed on new programs introduced over the course of the multi-year plan.
- Selection of the independent auditor to audit the Evaluation Report and determine the scope of the audit. The EAC will ensure that all comments on the Evaluation Report from the Consultative are reviewed by the auditor.
- Following the audit, review of the Evaluation Plan annually to confirm scope and priority of identified evaluation projects.
- The EAC will be responsible for meeting the reporting guidelines of the Board (found at Section 2.1.12 of the Natural Gas Reporting & Record Keeping Requirements Rule for Gas Utilities). The EAC will provide a final report within 10 weeks from the later of, the receipt of the Evaluation Report and supporting evaluation studies from the Utility, or the hiring of the auditor. Recommendations of the EAC with respect to DSMVA, LRAM and SSM clearances shall be included in the EAC's final report. The EAC shall not consider any further information subsequent to the Board's filing deadline each year."

What characteristics are required to determine that a program is either a market transformation or lost opportunity program? (Issue 10.1)

"Market Transformation programs are those that (a) seek to make a permanent change in the market for a particular measure, (b) are not necessarily measured by number of participants and (c) have a long term horizon.

Lost Opportunity programs are those that focus on DSM opportunities that will not be available, or will be substantially more expensive to implement, in a subsequent planning period."

How should it be determined that utility has achieved any prescribed target? (Issue 10.3)

and

What should be the length of a market transformation and lost opportunity program? (Issue 10.5)

and

What is the appropriate level of funding for a market transformation or lost opportunity program? (Issue 10.6)

Settlement on these issues was referred to completely settled Issue 10.7.

How should a program incorporate the following elements; information and education activities; incentives; research; activities to reduce market barriers such as building codes and energy efficiency appliance standards; and coordination with other entities (e.g. OPA)? (Issue 10.7)

"For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

Is it appropriate to use DSM funds for fuel switching to natural gas? (Issue 14.1)

> "Fuel switching is an important activity that can help alleviate some of the electricity supply programs faced by the province; however, the utility shall not use DSM funding to promote fuel switching to natural gas. The utility will pursue fuel switching activities as part of its marketing efforts that will be included in its rate case or other suitable application."

Is it appropriate to use DSM funds for fuel switching away from natural gas? (Issue 14.2)

> "Where fuel switching away from natural gas aligns with the Utility's DSM objectives the Utility may pursue these activities."

CHAPTER 3- PARTIAL SETTLEMENT (FINANCIAL PACKAGE)

In addition to the completely settled issues, the Board was presented with a list of partially settled issues. Union, EGD, CCC, SEC, Energy Probe, IGUA, LPMA, and VECC (the "Partial Settlement Proponents") were parties to a complete agreement on a number of issues. Certain of these issues were presented as a package (the "Financial Package") which the parties presented as being un-severable; i.e. if the Board did not accept the entire package, the Financial Package agreement would be withdrawn. The Financial Package dealt with:

- DSM budgets (Issue 1.3),
- DSM plan targets (Issue 1.4),
- allocation of DSM budgets amongst customer classes (Issue 1.7),
- the DSM incentive mechanism (Issue 5.2),
- the DSM variance account (Issues 6.1, 6.2, 6.3),
- market transformation and lost opportunity program budgets and utility incentives related to them (Issues 10.2, 10.4, 10.8), and
- targeted programs for low income customers (Issues 13.1, 13.2, 13.3).

The Partial Settlement Proponents explained that the individual elements of the Financial Package were tied together, and that to change one element would have repercussions on other elements. On the opening day of the hearing, the Board explained to the parties that it would hear whatever evidence the parties chose to lead; however, if at the conclusion of the hearing the Board determined that it did not wish to accept the Financial Package in its entirety, it would not re-open the hearing to hear fresh evidence on any of the issues. The Partial Settlement Proponents subsequently informed the Board that they would continue to exclusively support the Financial Package, and would not present any evidence to be considered in the event that the Board did not accept the entire Financial Package.

In addition to the Financial Package, the Partial Settlement Proponents reached a partial settlement on a number of other issues that could be considered individually. This chapter deals only with the Financial Package; the remaining partially settled issues will be addressed in Chapter 4.

The chief proponents of the Financial Package in the hearing were the utilities through their witness panels. The other Partial Settlement Proponents did not present witnesses in support of the Financial Package, but did conduct what was described as “friendly” examinations of the utility witnesses on these issues. The parties opposed to the Financial Package cross-examined the utility witnesses and, in some cases, filed their own proposals.

The Board will accept the Financial Package as presented by the Partial Settlement Proponents. As the Board explained when considering the meaning of a partial settlement on July 10, the Board has considered all of the issues in the Financial Package on an issue by issue basis. Taken individually and as a whole, the Board finds all of the proposals contained in the Financial Package to be reasonable.

The Board is pleased that the Financial Package amounts to what is largely a “rules-based” approach. Many of the major elements of the three year DSM plans will essentially be locked in for the term of the plan, and will not require further review by the Board during this period. This should result in significant regulatory savings for the parties, the Board, and, ultimately, for ratepayers.

The Board finds that the Financial Package strikes an appropriate balance between advancing DSM forward through higher budgets and ultimately higher TRC savings targets, while not forcing the utilities to try to spend money that they indicated they would have trouble spending in a cost effective manner. The Board is also satisfied that the Financial Package will not cause undue rate impacts to ratepayers given the relatively modest nature of the proposals, in light of the overall revenue requirement of the respective utilities.

In addition to the overall comments above, the Board has the following remarks on the individual issues that comprise the Financial Package.

How should the financial budget be determined? (Issue 1.3)

The Partial Settlement makes the following proposal.

> "Parties in agreement with this partial settlement accept that a DSM budget cap should be developed using the following formulaic approach in each year of a multi-year DSM plan. For the first year, the budget for EGD will be $22.0 million, an increase of $3.1 million or approximately 16% from its 2006 budget. For Union, the 2007 budget will be $17.0 million an increase of $3.1 million or approximately 22% from its 2006 budget.
>
> In the second and subsequent years of a multi-year DSM plan, the DSM budget for each year of the plan will be determined by applying an escalation factor of 5.0% for EGD and 10% for Union to the budget developed for the immediately preceding year. The purpose of the application of different escalation factors for EGD and Union is to address the desire by some parties that the difference between the level of spending by EGD and Union be narrowed. The parties agree that this formula results in budgets of $23.1 million and $24.3 million for EGD in 2008 and 2009 respectively, and budgets of $18.7 million and $20.6 million for Union in 2008 and 2009 respectively.
>
> Parties to this partial settlement agree that the Utilities remain obligated to develop, and spend monies on, cost-effective DSM programs up to the budget amount developed by this methodology."

The Board is satisfied that the Financial Package proposal reaches an appropriate balance between increasing DSM budgets and approving budgets which can be spent in a cost effective manner. Both Pollution Probe and GEC argued in favour of much higher budgets; however, the Board is not convinced that the utilities could currently spend these amounts cost-effectively.

Should there be plan targets and if so, should they be volumetric or based on TRC values? (Issue 1.4)

The Financial Package agreement makes the following proposal:

> “Parties to this partial settlement further agree that there will be an annual TRC target. The parties agree to phase in a formula over the next three years which will set this target, as described below, by averaging the Utility’s actual audited TRC results over the previous three years and applying to this figure an escalation factor equal to 1.5 times the amount by which the utility’s budget is increased. The parties agree to phase in the aforementioned formula over the next three years beginning with an agreed upon target for each utility in 2007 which, for Union will be $188 million and for EGD $150 million.
>
> Furthermore, the parties agree that, in the event the avoided costs used by the utility are, at a later date, updated, the actual audited results from previous years used to calculate the target will be adjusted to reflect these updated avoided costs.
>
> Finally, and for greater certainty (and as an example), set out below is the formula by which the target will be set for Union, with 2010 provided for illustrative purposes only:
>
> • 2007 - $188 million.
>
> • 2008 - The simple average of $188 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2009 - The simple average of $188 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

• 2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 15%).

For EGD, the formula by which the target will be set is as follows, with 2010 provided for illustrative purposes only:

• 2007 - $150 million

• 2008 - The simple average of $150 million and the actual 2007 audited TRC value as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

• 2009 - The simple average of $150 million and the actual 2007 and 2008 audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie. 7.5%).

•2010 - The simple average of the previous three years actual audited TRC values as approved by the Board increased by 1.5 times the budget escalation factor (ie.7.5%).

The “actual audited TRC values” shall be the total TRC produced for the year in question as determined by the audit in the following year. In setting the target for 2009 and subsequent years, the actual audited TRC value for the immediately preceding year, but not for the prior two years used in the average, will be adjusted to reflect any changes in input assumptions determined in the audit to apply to that year for LRAM purposes. By way of example, if a free rider rate is increased in the 2009 audit carried out in the first half of 2010, under the partial settlement that change would normally apply to SSM for the years 2010 and thereafter, but to LRAM for 2009 as well. In calculating the target for 2010, the three year average will use the TRC values otherwise determined for 2007 and 2008, but for 2009 will use the audited TRC values, adjusted for that change in free rider rate identified in the audit.”

The Board is satisfied that the Financial Package proposal sets reasonable TRC targets for the utilities. The Board notes that the formula used to derive the targets in years two and three of the plan is self adjusting to account for actual performance in the previous year. The Board finds this formula to be preferable to setting the targets for all three years in advance.

The Board notes that the target for Union in year one of the plan will actually be lower than its Board approved target for 2006. The Board heard evidence from Union that the TRC target for 2006 had been set at a level that it will not attain. Union indicated that according to its current projections for 2006, the company will likely achieve TRC savings in the range of $170 million (on a target of $216 million). The Board accepts Union's evidence in this regard, and finds that a target of $188 million in year one of the three-year plan is reasonable.

On what basis should the DSM program spending be targeted amongst customer classes? (Issue 1.7)

The Financial Package agreement makes the following proposal:

> "Parties acknowledge that EGD's and Union's rate classes and customer needs are not identical, and hence it is not appropriate to restrict spending based on a rigid formulaic approach by rate class. The Utilities acknowledge and accept the principle that their portfolio of DSM programs should provide customers in all rate classes and sectors with equitable access to DSM program(s) to the extent reasonable, and that this principle must be balanced and consistent with the principle of optimizing cost-effective DSM opportunities. To the extent that a proposed multi-year plan proposes DSM sector (ie. residential, commercial, or industrial) level spending that is significantly different than the historical percentage levels of spending in those sectors, the utility will provide its explanation for this in its proposed multi-year plan. Parties may challenge any such

explanation, or its impacts. The Board will then determine whether to approve the revised spending ratios, and if so, under what conditions.

To the extent that actual sector level spending then varies significantly from the ratios identified in the plan, parties may challenge the appropriateness of the deviation from the plan when the utility seeks approval for the clearance of relevant accounts and the Board can make such order as is appropriate. (Issue 1.7)"

The Board is cognisant of the tension between ensuring that each rate class is allocated an appropriate portion of DSM funds on the one hand, and the benefits of targeting spending to the most cost effective programs regardless of what rate class they fall in on the other. The Board is satisfied that the Financial Package proposal finds the appropriate balance.

What is an appropriate incentive mechanism and how should it be calculated? (Issue 5.2)

The Financial Package agreement makes the following proposal:

"The parties to this agreement agree that an SSM shall be established for the first year of the plan and shall be in effect for each year of each multi-year plan.

Parties agree that the amount of any SSM shall not be included in the Utility's return on equity ("ROE") for the purposes of setting rates or in the calculation of any earnings sharing amounts.

The parties agree that for the purposes of this settlement, the TRC indexing target for 2007 for EGD will be $150 million, and for Union, $188 million. Targets for subsequent years shall be set in accordance with the formula in Issue 1.4. The cumulative SSM incentive payment to each utility for achieving their respective TRC target will be set by a formula, and at 100% of TRC target will be $4.75 million. For the purposes of determining whether each utility has met its 100% TRC target, the input assumptions for the calculation of SSM will not be changed retroactively. For clarity, changes to input assumptions, which are confirmed through audit, apply in the year immediately following the year being audited. For example, input assumptions for purposes of the SSM remain fixed for 2007, and any changes to input assumptions which change as a result of the audit of the 2007 results which is undertaken in early/mid-2008 will apply from the beginning of the 2008 year forward. Also see Issue 3.3.

For both Utilities, the following formula applies for the determination of the SSM curve and resulting cumulative payout. The SSM payout will be calculated based on the results as they apply along the curve and each of the following percentage thresholds do not represent lump sum payments for reaching the threshold but simply serve to structure the SSM curve based on targets and SSM amounts as agreed to by the supporting parties:

Up to 25% of the annual target, a total payout of $225,000
Up to 50% of the annual target, a total payout of $675,000
Up to 75% of the annual target, a total payout of $2,250,000
Up to 100% of the annual target, a total payout of $4,750,000
Up to 125% of the annual target, a total payout of $7,250,000
In excess of 125% of the annual target, a total that is capped at no more than $8,500,000.

The parties agree that the annual ‘cap’ of $8.5 million will increase annually by the Ontario CPI as determined in October of the preceding year (i.e., the 2008 cap will increase based on CPI as determined at October of 2007).

See also issue 10.4 for the incentive available to the utilities in respect of market transformation programs”

During the hearing, the utilities provided the formula in calculating SSM, which is reproduced below:

> "For achievement of between 0 and up to 25.0% of the annual target, the SSM payout shall equal $900 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 25.0% up to 50% of the annual target, the SSM payout shall equal $225,000 plus $1,800 for each 1/10 of 1% of target achieved.
>
> For achievement of greater than 50.0% up to 75.0% of the annual target, the SSM payout shall equal $675,000 plus $6,300 for each 1/10 of 1% of target achieved above 50.0%, and
>
> For achievement of greater than 75.0% of the annual target, the SSM payout shall equal $2,250,000 plus $10,000 for each 1/10 of 1% of target achieved above 75.0% to a maximum of the SSM annual cap."

There was a complete settlement on issue 5.1, in which all parties agreed that there should be an incentive mechanism. The Financial Package proposal for issue 5.2 presents a formula for determining the exact amount of the SSM payout based on the level of success each utility has achieved in hitting its TRC targets. The Financial Package proposal calls for an escalating incentive scale which starts at the first dollar of TRC net benefits achieved. This proposal marks a change from the current Board approved practice where the utilities are required to reach a certain level of net TRC savings before any incentive is realized. The Board is satisfied that this change to the *status quo* is appropriate. The Board is persuaded by the utilities' evidence that the proposed structure is more likely to attract management attention to DSM programs. The Board is also comforted by the fact that the incentive payments for performance below 50% of the TRC target is very low. Further, the $8.5 million cap on incentive payments for any one year ensures that ratepayers will not have to pay an undue amount if a utility achieves extraordinary success.

Demand Side Management Variance Account (Issues 6.1, 6.2, 6.3)

The Financial Package agreement makes the following proposals:

> "Parties agree that the DSMVA shall be continued. The DSMVA shall be used to "true-up" the variance between the spending estimate built into rates for the year and the actual spending in that year. If spending is less than what was built into rates, ratepayers shall be reimbursed. If more is spent than was built into rates, the utility shall be reimbursed up to a maximum of 15% of its DSM budget for the year. All additional funding must be utilized on incremental program expenses only (i.e. cannot be used for additional utility overheads). For greater certainty, program expenses include market transformation programs. "
>
> "There should be no limit on the amount of under spending from budget that should be returned to ratepayers. Parties agree that a Utility may spend and record in the DSMVA for reimbursement to the utility, in any one year, no more than 15% (fifteen per cent) of that Utility's DSM budget for that year. "

The Board finds the Financial Package proposal to be reasonable. The DSMVA will allow utilities to aggressively pursue programs which prove to be very successful, even where this causes them to exceed the Board approved budget (by up to 15%). It will also ensure that unspent DSM funds are returned to ratepayers.

Market Transformation (Issues 10.2, 10.4, 10.8)

The Financial Package agreement makes the following proposals:

> "Every utility DSM plan should include an emphasis on lost opportunity and market transformation programs and activities. For purposes of this agreement, parties agree that this emphasis will consist of a market transformation budget of $1.0 million per utility per year and is included in the total budget amounts referenced in issue 1.3."
>
> "Parties agree that each utility is entitled to an incentive payment of up to $0.5 million in each year of the multi-year plan based on the measured success of market transformation programs. The measurement and calculation methodologies to determine whether this amount has been earned in the year shall be detailed by each utility in its multi-year DSM plan. For clarity, this amount is in addition to any amount earned at issue 5.2. By way of example, a Utility may propose in its DSM plan a program to increase the market share of a particular high efficiency product, and a $250,000 annual incentive based on the market share of that product at the end of each year, measured by a specific third party market index, being 10% higher than the previous year. If the DSM plan is approved by the Board including that program, the Utility will be entitled to a $250,000 incentive in each year that it meets the stated market share goal."
>
> "For each market transformation program the utility should, in its multi-year plan, propose a program description, goals (including measurement method), incentive (including structure and payment), length, level of funding and program elements. Such programs are not amenable to a formulaic approach and therefore should be assessed on their own merits and all of the above components should be suitable given the subject matter and program goals."

The Board is satisfied with the Financial Package proposal for market transformation. GEC argued for a much larger budget for market transformation and lost opportunity projects. Utility witnesses stated that the utilities could not effectively spend these budgets. The Board notes that the proposal regarding utility incentives for these programs does not achieve the level of certainty that exists for other elements of the Financial Package. While GEC argued for a more concrete incentive mechanism, the witnesses at the hearing were largely in agreement that market transformation programs are not necessarily amenable to fixed and inflexible rules. The Board agrees. The Board therefore accepts the proposal as filed.

Targeted Programs (Issues 13.1, 13.2, 13.3)

The Financial Package agreement makes the following proposals:

> “Parties to this settlement accept that low-income customers face barriers to access DSM programs which are unique to this group of customers. Accordingly, parties to this settlement agree that it is appropriate to establish a minimum amount of spending on targeted low-income customer programs in the residential rate classes of both Utilities. It is agreed that each utility will spend out of its DSM budget a minimum of $1.3 million, or 14% of each respective utility’s residential DSM program budget, whichever is greater. For clarity, a utility may expend more than $1.3 million or 14% of its residential DSM program budget if the utility considers it appropriate. The Utilities each agree to increase the $1.3 million spending floor by the budget escalation factor appropriate for the utility (i.e. EGD 5%; Union 10%) in each of the second and third years of a three year plan.
>
> The parties to this settlement further agree that of the $1.0 million budget for market transformation programs, each utility will expend no less than 14% on targeted low-income market transformation programs.

> The Utilities agree that by the establishment of this spending level floor, they will not, as a result, reduce planned DSM spending in other rate classes or sectors which are directed at low-income residents (e.g. social housing multi-unit residential spending) or their spending on fuel switching targeted to low-income customers."
>
> "Each of the utilities is at liberty to develop appropriate eligibility criteria for low income residential programs, and each utility agrees to consult with VECC in respect of the development of eligibility criteria and low-income program parameters. Parties to this settlement generally accept that criteria presently used by various levels of government for the purposes of determining low income eligibility may be appropriate for use by the utilities."

The only customer segment proposed to the Board for targeted programs were those for low-income customers. The Board finds the Financial Package proposal to be reasonable. The proposed spending floor should ensure that low-income consumers have access to DSM programs at least in approximate proportion to their percentage of residential revenue. LIEN argued that spending on low-income DSM programs should be equal to 18% of the total residential class DSM budget, assuming the total DSM budget is split proportionately amongst all rate classes. Under Issue 1.7, the Board has already stated its acceptance of budget allocations that are not strictly proportional to customer class revenue. There was conflicting evidence in the hearing as to the estimated proportion of low-income households within the residential sector. LIEN argued that the proportion was 18% while the Partial Settlement proponents argued that 14% was closer to the actual proportion. The Board finds LIEN's evidence on this matter unconvincing and finds that 14% is supported by the evidence. The Board, therefore, accepts the proposal that each utility will annually spend 14% of the residential DSM budget or $1.3 million on low-income programs, whichever amount is greater.

CHAPTER 4 - REMAINING NON-SETTLED ISSUES

The previous chapter, Chapter 3, dealt with the settled issues and the partially settled issues that were presented to the Board as a “financial package”. The following chapter, Chapter 5, includes discussion of Issue 3.2 relating to the question of whether there should be a common guide. This chapter, Chapter 4, deals with the remaining non-settled issues that were addressed during the oral hearing.

What should be the timing of the schedule for submitting and reviewing Demand Side Management (“DSM”) plans? (Issue 1.1)

The Board was presented with a partial settlement. All intervenors agreed as follows:

> “…DSM plans should be filed at least nine months prior to the plan period to which they relate, to give sufficient time for stakeholders and the Board to consider them, and for Board approval prior to the plan period commencing.”

The utilities believe that filing the DSM plans four months in advance of the initial plan year will allow sufficient time to have the plan in place by the beginning of the following year. The utilities indicated that this would allow them to file final results from the previous year’s audit, rather than interim un-audited results.

For clarity, the timing issue here relates to future DSM plans. The timing of filing for the inaugural three-year plan is dealt with elsewhere in this decision.

The Board notes that a filing date at least nine months in advance would entail the presentation of un-audited performance of the plan’s second year. This may likely involve updates once the results are audited. The Board is of the view that updates should be avoided where possible, as they are generally not conducive to an efficient review. While the Board anticipates that a four month time frame will likely be adequate to accomplish the review given the rules approach adopted by the Board, there is the possibility that it will not. In that case, the consequence is a start date that may not immediately follow the last day of the previous term of the plan. While this may not be desirable, it would be of little adverse consequence as the previous plan would continue. It is in the Board's view a reasonable risk to take in order to obtain the benefits of an efficient review. The Board therefore accepts the utilities' proposals that subsequent plans be filed four months in advance of their commencement.

What process and rules should be available to amend the DSM plan? (Issue 1.5)

There was no settlement (complete or partial) on this issue.

In a response to an undertaking (J2.2), the utilities referenced the preamble of the Partial Settlement which reads

> "For greater clarity, where any settled issue is expressed to continue throughout a multi-year plan, no party to that settlement may seek to re-open that issue with respect to either Utility in any other proceeding prior to the earlier of a) the Board's consideration of the multi-year plan of that Utility, or b) a further hearing on DSM in which the Board has determined that such issue is to be considered "

and stated that

> "… it is the position of the utilities that the Board should amend a multi-year plan during the currency of that plan only in exceptional circumstances. It is expected that with the proposed language, all stakeholders will recognize that any application for an amendment must meet a very high onus to demonstrate undue harm. The intent of the above section is not to provide parties with an opportunity to reopen the framework rules established in this proceeding."

As noted at the oral hearing, no rule can prevent requests for review, or should for that matter. It would not be in the public interest to disallow re-opening of the plan in midstream under any circumstances. At the same time, the purpose of this generic initiative is to avoid unnecessary re-visitation of DSM issues.

Demonstration of "undue harm" was accepted as a reasonable principle by intervenors. The Board concurs that it is a workable principle and useful in the circumstances. There was also support for the proposal by SEC that any party claiming undue harm must first seek leave of the Board before the matter is thoroughly reviewed, and leave should be given only in exceptional circumstances. The Board notes that if a proposed amendment came forward either by way of a motion or by way of application, the Board has the authority and tools to subject the request to the appropriate scrutiny, and to ensure that the intentions of the parties and the Board are respected.

As for the proposal by the utilities that the Board use its cost assessment powers as a further measure to dissuade frivolous requests, this option is always available to the Board and can be used when warranted. This applies equally to intervenors and the utilities.

Should a TRC threshold be established to determine if a measure and/or program is cost effective or should it be based on the cost effectiveness of the portfolio? If so, what should the value be? (Issue 2.2)

The Board was presented with a partial settlement. All parties except SEC agreed as follows:

"The general principle is that all measures and programs should exceed a benefit to cost ratio of 1.0 to be included in the portfolio, but exceptions are reasonable where other benefits are apparent (e.g., pilot programs)."

SEC argued for a screen value of 1.2 rather than 1.0 on the basis that TRC is based on assumptions that change, so it would be appropriate to build in a margin to ensure feasibility. SEC noted that nothing is lost since it appears that there is much more DSM available than the utilities can handle and thus, instituting a higher threshold programs would be better. SEC noted that the exception related to the screen value for pilot programs would still exist.

In the Board's view, the availability of DSM initiatives that exceed the 1.0 cost-benefit ratio is not a compelling argument for deviating from a widely-practiced threshold of 1.0. A program that yields a benefit cost ratio over 1.0 does provide positive net benefits and it would not be appropriate to knowingly forego such benefits. As for SEC's argument that a higher threshold would avoid the risk of uneconomic programs, this can be addressed by instituting more robust input assumptions. Moreover, the risk of uneconomic programs is offset by the fact that, from a societal perspective, the TRC test does not reflect the positive aspects of mitigating negative externalities that are inherent in gas consuming activities. In fact the risk of undertaking uneconomic programs is self-correcting by the incentive by the utilities to maximize rewards by maximizing TRC benefits. For the above reasons, the Board does not accept SEC's suggestion.

However, the Board notes that the partial settlement refers to pilot programs as an example of programs where an exception to the threshold of 1.0 may be permitted. The implication is that there may be other types of programs. No other examples were provided. The Board prefers more certainty as to the exceptions in these circumstances. The Board therefore finds that the exception to the TRC threshold should be restricted to pilot programs at this time.

How often should avoided gas costs be calculated and should the Local Distribution Companies ("LDCs") use identical avoided costs? (Issue 3.5)

There was no settlement (complete or partial) on this issue.

EGD undertook to explore if the utilities could produce a common set of avoided costs and responded (J2.4) as follows:

> "Each Utility will calculate avoided costs for natural gas, electricity and water that reflect the cost structure and service territory of the Utility. In order to ensure consistency, a common methodology will be used to determine the costs. The Utilities will coordinate the timing for selecting commodity costs so that they are comparable.
>
> The avoided costs will be submitted for review as part of the multi-year plan filing and should be in place for the duration of the plan. The commodity portion of the avoided costs will be updated annually.
>
> As avoided costs are long term projections, updating the costs, other than the commodity costs, on a three year cycle should not cause benefits to be significantly under or overstated. Regardless of how often the avoided costs are updated, the same avoided costs will be used to calculate both the target (relative to 2007) and incentive amount, therefore it is anticipated that the relative impact would be minimal."

Only GEC argued against the utilities' proposal. It argued that the utilities should use common values for gas commodity, electricity and water. With respect to the avoided distribution system costs (e.g. pipes and storage etc.) which may vary by utility, GEC submitted that the utilities should be required to demonstrate how different these values are so that the Board can determine whether or not the difference is material.

The Board does not accept GEC's proposals. Avoided gas costs are a significant component of calculating TRC benefits. Gas costs can be different for each utility depending on, among other things, its gas supply management policies and practices.

With respect to system costs, these are certainly unique to each utility and they too are an important part of the TRC benefit calculation. The benefits of estimating and measuring with more precision the TRC values for DSM programs outweigh, in the Board's view, the costs of the incremental effort to determine and review the different values for gas commodity and system costs.

The Board also notes that the methodology for estimating the values for natural gas commodity, system costs, electricity and water will be common for the two utilities, which will ensure some measure of consistency and efficiency.

The Board accepts the utilities' proposals.

Should the LDCs be entitled to revenue protection? (Issue 4.1)

The Board was presented with a partial settlement on this issue. All parties except CME agreed that the utilities should be entitled to revenue protection.

By accepting the "financial package" settled issues earlier in this decision, the Board has not found merit in CME's argument that the utilities should not be entitled to revenue protection. As long as a utility's fixed costs are not fully recovered through fixed charges (and part of the fixed costs are therefore being recovered through the variable charges), there is an inherent conflict for the utility between sales growth and conservation. The existence of a mechanism to neutralize this conflict through an LRAM mechanism is therefore essential to the success of DSM.

What is the appropriate level of funds that should be budgeted for an evaluation report and audit? (Issue 9.2)

The Board was presented with a partial settlement on this issue. All parties except GEC agreed as follows:

"The Utilities shall ensure that DSM budgets and spending include adequate funding to complete the required annual evaluation and audit activities. The utility is responsible and accountable to ensure that evaluation and auditing activities are concluded in a timely fashion and that the associated costs are reasonable."

GEC argued that 3% of the DSM budget should be allocated to evaluation and audit over the three year period. GEC noted that the utility should have the flexibility to move spending between years to balance the lumpiness of spending. GEC noted that this budget should only be spent if required.

The Board fails to see the rationale or benefit of GEC's suggestion. In fact the Board only sees lost DSM program opportunities as the utilities will not be able to access any unspent portion of a fixed budget reserved for evaluation and audit. The Board does not accept GEC's proposal. The utilities should be spending in evaluation and audit as required and as prudent.

What attribution rules or principles should be applied to jointly delivered DSM programs? (Issue 11.1)

There was no settlement (complete or partial) on this issue.

The issue for the parties was how the framework rules will deal with situations where a utility operates or participates in a program with a non-rate-regulated third party and, where this occurs, how should the determination of the TRC benefits be made. For completeness, the Board also makes a finding on attribution between Board rate-regulated parties.

The utilities advocated the centrality principle, as decided by the Board in EGD's EB-2005-0001 rate case. Under the centrality principle, it would be considered that the utility played a central role if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. In such circumstances the utility would be entitled to 100% of the TRC benefits.

Where the utility's role is not considered central, the utilities differed. EGD advocated a scaled role approach, whereas Union proposed that the attribution of TRC benefits would be measured by free ridership. In Union's view, there is no material distinction in the two approaches as both would likely produce the same result. The utilities agreed that it should be the same arrangement for both as determined by the Board.

In the view of CCC and GEC, the rule of centrality is not particularly helpful at avoiding the need to analyze each project or proposal.

The Board notes that the utilities did not dispute the suggestion that attribution of benefits for jointly delivered DSM programs must be done on a case-by-case basis. The Board agrees that this is a reasonable approach. The issue is whether the centrality principle should be maintained.

The Board recognizes that it accepted the centrality principle in the EB-2005-0001 rate case when it dealt with EGD's EnerGuide for Houses program. What makes the re-assessment necessary is the fact that this is a generic hearing for the gas distributors and it is appropriate to review the rules *de novo*. In that regard, the Board notes that, pursuant to the settled and approved issues, there is now a delineated role for the evaluation and audit committee in respect of programs pursuant to the settlement agreement and the Board's acceptance of the agreement. Specifically, the attribution rules set by the Board will be used by the evaluation and audit committee to assess and settle the TRC savings attributable to the utility's role, which will ultimately be reviewed by the Board.

As the utilities concede, the centrality rule is not absolute. There can be considerable judgment in determining whether or not the role of the utility is central in a particular program. Attribution on the basis of the utility's participation that is considered incremental to the program on the other hand appears to remove some of the controversy, and it does not preclude full 100% attribution to the utility. However, a drawback is that the incrementality approach may not adequately and fairly capture situations where a program would not have existed at all if it were not for the utilities.

On balance, the Board accepts the centrality principle for purposes of the first multi-year DSM plans, under which the utility would be entitled to 100% of the TRC benefits if it can be demonstrated that it has a central role in a program. That is, as the utilities proposed, if the utility initiated the partnership, initiated the program, funded the program, or implemented the program. The experience to be gained over the next three years will inform as to the suitability of continuing with this approach after that point.

This leaves the difference in approach by the two utilities where centrality is not claimed or demonstrated.

The Board accepts the utilities' position that the distinction between their approaches is without a difference. The utilities' differences reflect different internal practices, as noted by the utilities. The utilities acknowledge that either approach would involve the evaluation of attribution of each program by the evaluation and audit committee, and ultimately by the Board. However the utilities accept that there should only be one common approach, to be determined by the Board.

The Board prefers the free ridership approach advocated by Union as this would be more consistent with the general approach for measuring TRC benefits in other DSM activities implemented by the utilities.

The TRC benefits for program partnerships with Board rate-regulated entities (e.g. electricity distributors) shall be allocated in the manner indicated in the electric TRC Guide, as was canvassed at the oral hearing. That is, a gas distributor partnering with an electricity distributor shall claim all of the benefits associated with the gas savings.

How should existing or future carbon dioxide offset credits be dealt with in DSM plans and programs, if at all? (Issue 11.2)

The Board was presented with a partial agreement on this issue. All intervenors agreed as follows:

> "Until the rules are known, a deferral account should be established for each Utility and any dollar amounts representing proceeds from the sale or other dealings in credits should be credited to that account".

The utilities submitted that until the rules of carbon dioxide offset credits are known, the Board should not make any determination on this issue.

The Board accepts the argument by certain intervenors that there is no harm in ordering a deferral account to capture any future carbon dioxide offset credits. While the matter could wait until the resolution, if any, of the carbon dioxide offset credits matter, the utilities did not present convincing arguments to counter the no harm proposition advanced by many intervenors. The Board is generally reluctant to authorize the establishment of deferral accounts without a more concrete and immediate need. However since this matter is within the scope of DSM, there is an opportunity to deal with it now without the need for further processes. Therefore the Board concludes that the establishment of a deferral account would be a reasonable approach in the circumstances, and so orders.

Should free riders for custom projects be determined on a portfolio average or on a project basis? (Issue 12.1)

There was no settlement (complete or partial) on this issue.

The utilities proposed that the free ridership rate should be determined on a portfolio average basis. The single free ridership rate would apply across a number of technologies and a number of sectors. The utilities proposed a free ridership rate of 30%.

VECC submitted that although the fairest way to address attribution for custom projects would be on a project-by-project basis, a portfolio average approach can be acceptable for administrative efficiency, but with the conditions that there should be emphasis on sector-by-sector as suggested by LPMA.

The Board sees merit in the notion of differentiated free ridership rates by market segment, at least for large and small enterprises. However, this is a significant undertaking. The utilities revealed that at present there are over one thousand custom projects within EGD and a fifth of that within Union. A segmentation analysis would need to be done on a sample basis, statistically justified, and reviewed by the parties and the Board. Ordering such studies for the two utilities for this plan may jeopardize the timetable of filing and implementing the respective DSM plans. The Board also notes the testimony by Union's witness that any differences in free ridership rates through market segmentation may at the end balance out and in fact support a single rate.

For these reasons the Board accepts a portfolio average approach for custom projects. The free ridership rate for custom projects will be determined as part of the process that will determine the input assumptions.

For the next generation multi-year plans, the Board expects the utilities to propose common free ridership rates for custom projects that are differentiated appropriately by market segment and technologies.

Should custom projects have a third party or an internal audit and if so, what would be the audit scope and process of the audit? (Issue 12.2)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Custom projects should be audited using the same principles as any other programs. Audit activities should be sufficient for the auditor to form

> an opinion on the overall SSM, LRAM and DSMVA amounts proposed in the Evaluation Report."

EGD proposed that the custom projects be audited as part of its portfolio results based on a significantly appropriate representative sample. The auditor would then confirm the results and these would be included for the purposes of calculating SSM and LRAM, consistent with the completely settled Issue 3.3.

Union proposed that, as custom projects form a large part of Union's DSM portfolio, they should be assessed by a third party, and noted that this is in fact Union's current practice. Union explained that a statistically significant sample of both the largest and smallest subset of projects should be evaluated by a third party evaluator, hired by the utility. The evaluator would not be the auditor because of the particular technical expertise required to review custom projects. The report of the technical expert would form part of the evaluation report, which would be forwarded to the auditor.

The Board notes that the distinction between the Union and EGD proposals is that, in Union's case, the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor. In EGD's case, that first cut is done in-house but EGD still engages a third party to do an evaluation of the sampling of its custom projects. Although in both cases the results would be forwarded to the auditor for review, the Board is of the view that a common approach should be adopted for the two utilities. The Board prefers Union's current practice where the third-party evaluator does the statistical sampling and the initial review of the project before they form part of the evaluation report that is forwarded to the auditor.

Union proposed the adoption of the rule in the TRC handbook for electric CDM, where the projects selected for assessment should consist of a random selection of 10% of the large custom projects representing at least 10% of the total volume savings for all custom projects and consist of a minimum number of five projects. The Board adopts this proposal, which shall apply to both utilities.

[With respect to custom projects], how should savings be determined and what documentation is required? (Issue 12.3)

The Board received a partial settlement on this issue. All intervenors agreed as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life, so for example should include a factor for the possibility that a measure will not be used for its entire engineering life (due to bankruptcy, change in operations, etc.)."

During the hearing, a complete settlement was considered to have been reached by all parties by truncating the text as follows:

> "Assumptions used should comply with the principles set out under Issue 3.3. Assumptions with respect to measure life should reflect actual expected measure life."

The Board concurs with the settlement.

[With respect to custom projects], should the volumetric savings recorded be actual or forecasted volumes and what documentation is required to verify this result? (Issue 12.4)

In the Partial Settlement, parties referred this issue to Issue 12.3, which in turn was considered to have settled by the parties during the hearing.

The Board approves this settlement.

[With respect to custom projects], how will an appropriate base case be determined? (Issue 12.5)

The Board was presented with a partial settlement on this issue. All intervenors and Union agreed as follows:

> "Only the part of the project that the Utility influenced is to be counted for SSM or LRAM purposes."

The Board notes that only EGD opted out on the basis that it does not know the implications of the word "influence". The Board is not in a position to provide assistance to EGD in this regard as EGD itself was not clear as to the relief that it is seeking. However, the Board's findings in this decision taken in their entirety should help alleviate EGD's concerns. In particular, the Board does not see how the proposed wording would invalidate settled Issue 3.3, which is EGD's stated concern.

The Board accepts the partial settlement on this issue.

How should the funding levels and targets, if any, for the gas utilities' electricity to natural gas fuel switching programs be determined? (Issue 14.3)

The Board was presented with a partial settlement on this issue. All intervenors agreed as follows:

> "Programs promoting fuel switching to natural gas, which should be funded from the marketing budget of the Utility, should, just as with DSM programs, seek to balance maximization of TRC benefits with minimization of rate impacts."

Union noted that that all parties agreed that fuel-switching to natural gas is not a DSM activity (and DSM funds should not be used for this purpose) and fuel-switching away from natural gas may be appropriate in certain circumstances and may therefore constitute DSM. Union stated that it is simply seeking guidance from the Board or approval to bring an application in the future which will address the issue of the appropriate level of funding, as well as the target, if any, associated with fuel-switching, and thus how success ought to be measured.

EGD submitted that in accepting the completely settled issues in this matter, the Board has effectively deferred the issue to a future panel of the Board that will consider it in the context of whatever proceeding any fuel-switching budget is brought forward.

In this Board Panel's view, making findings, providing guidance or even commenting on the substantive matters of fuel switching would not be appropriate. In making this finding, the Panel was mindful of the impact any conclusions may have on a future panel of the Board. Equally important, there was an insufficient evidentiary basis in this proceeding for the consideration of limiting fuel-switching to a TRC test only. Parties that believe that a TRC test should be used for a fuel-switching budget will have the opportunity to raise this issue in future rate proceedings.

What is the appropriate role of gas utilities in electric CDM? (Issue 15.1)

There was no settlement (complete or partial) on this issue.

EGD submitted that it would like to have the flexibility to make its expertise in DSM available in the electric Conservation and Demand Management (CDM) arena. It also stated that it was not planning to engage in CDM consulting. Union stated that it does not plan to engage in electric CDM. However, Union supported EGD's submissions.

SEC stated that on the assumption that the utilities can engage in electric CDM activities under the Undertakings given to the Lieutenant Governor in Council (the "Undertakings"), it supported the idea that the gas utilities be able to do joint programs with the electric LDCs, as this would tend to lower costs for the gas utilities. SEC cautioned against diverting the gas utilities' attention from gas DSM programs to electric CDM since the latter is, in SEC's view, more lucrative. CCC noted that there is no like thinking by the two utilities on their role regarding DSM activities and that there is no necessary and rational connection between electricity CDM and the utility DSM programs; therefore, there is a need to impose some constraints on the utilities' activities. CCC also questioned the legality of the gas utilities engaging in these activities without proper dispensation under the Undertakings. GEC submitted that gas utilities should only engage in electric CDM when it enhances gas DSM; otherwise, it would be a competing demand on scarce resources and a distraction from their primary focus. VECC supported co-delivery of DSM and CDM measures as it would reduce program costs, but not on the basis of incremental costing and profit sharing. LPMA and VECC suggested that electric CDM should be considered a non-utility activity for revenue requirement purposes of the distribution business.

EGD responded that it does not need an order or dispensation from the Board to engage in electric DSM. It specifically noted that gas DSM itself already generates electricity TRC savings which are included in the SSM calculations. EGD also stated that CDM is consistent with the objectives set out in the Ontario Energy Board Act to promote energy conservation; the Act does not limit the objective to simply natural gas. Further, this matter was canvassed in the EGD's EB-2005-0001 rate case where the Board approved the 50/50 earnings sharing mechanism for the joint participation in the TAPS electric CDM program.

The Board considers that the regulatory construct in Ontario is the concept of a pure distribution utility. This is manifested in the Undertakings and in the Board's rulings for some time. Gas DSM has remained an activity within the corporate structure of the utility and there is no compelling reason to alter this at this time - neither the utilities nor the intervenors instigated or sought a change with respect to gas DSM.

Recent developments in electric CDM may likely bring opportunities for gas utilities to engage or enhance engagement in this area. EGD has some minor engagements with Toronto Hydro Electric Systems Limited ("THESL"). Union does not appear to have any immediate plans to enter the electric CDM field. EGD, however, is interested in possibly expanding its electric CDM role where it is appropriate to do so.

There appears to be strong support if not consensus that the gas utilities should be permitted to engage in electric CDM if such engagement brings about cost efficiencies and the clear focus of the utility's demand management activities should relate to gas. The concern that attention may be diverted from gas DSM to electric CDM is, in the Board's view, theoretical at this stage. It is not axiomatic that enhanced engagement in electric CDM by the gas utilities will necessarily result in lost opportunities for gas DSM. The two initiatives can co-exist in an optimal and workable fashion. This is especially the case where demand management involves funding initiatives, not infrastructure, which has been the experience thus far.

The Board therefore is not concerned about the gas utilities in their present corporate structure engaging in electric CDM as long as such activities can be reasonably viewed as complementary and ancillary to gas DSM and do not involve investments in infrastructure. An example of that is EGD's involvement with THESL in the TAPS program. In fact, the utilization of the demand management expertise residing in the gas utilities should be viewed positively from a public interest perspective given the well known challenges in the Province's electricity sector. In that regard, engagement by the gas utilities in programs aimed at switching from electricity to gas is encouraged.

The concern arises if the gas utilities undertake stand-alone electric CDM activities. That is, programs that are not or do not appear to be synergetic to or enhancing gas DSM, especially if they involved investments in infrastructure on account of electric CDM. This would alter the regulatory construct of a gas distribution utility which would necessitate a review under the Undertakings and the Board's regulatory policies.

The Board is hampered in its assessment of the appropriate role for gas utilities in these situations. The Board is concerned about granting what might be viewed as blanket approval for the utilities to engage in electric CDM activities without knowing exactly what types of activity this might entail. For example, it is not clear if the gas utilities would bid for participation in the recently announced $400 million in OPA funding for electric CDM programs. As noted, the Board would not be concerned about gas utility involvement in OPA-funded programs targeted at switching from electricity to gas. The Board's concerns are in connection with stand-alone electric CDM programs where the gas utilities take on a central role.

This leads to the issue of whether relief from the Undertakings is required for the utilities to engage in electric CDM. EGD's current CDM activities with THESL were approved in EGD's most recent rates case. This program, however, is clearly incidental to EGD's DSM activities and it does not entail a separate infrastructure. EGD is free to continue its relationship with THESL regarding the TAPS program, and either gas utility may engage in similar programs with other electric LDCs where the CDM activity is clearly incidental to the utilities' DSM activities, or to engage in electric CDM stand-alone programs aimed at switching from electricity to gas where no dedicated investment in electric infrastructure would be required.

However, it is certainly possible that some other electric CDM activities or programs would require relief from the Undertakings. The Board is not in a position to articulate these engagements. The Board has not heard sufficient evidence to determine what would be an appropriate involvement by the gas utilities in such circumstances. The Board will leave it to the utilities to make such proposals if they so wish when they come forward with their respective DSM plans.

What is the appropriate treatment of costs and revenues for electric CDM? (Issue 15.2)

and

What incentives, if any, should be paid for electric CDM activities? (Issue 15.3)

There was no settlement (complete or partial) on these issues.

The utilities proposed that the costing of electric DSM should be on an incremental basis and the net revenues be split 50/50 between shareholders and ratepayers. This is the current practice for the TAPS program between EGD and THESL which was approved in the EB-2005-0001 rate case decision.

Some intervenors argued for full costing on the basis that it would avoid concerns about cross-subsidy between gas and electricity ratepayers. Full costing would also lower the net revenues to be split, thereby reducing the utilities' incentive to divert resources from DSM to CDM activities that may be more lucrative.

The Board notes that there was no opposition by intervenors to the institution of the 50/50 net revenue split proposal. The Board accepts the proposal as reasonable.

The utilities' proposal to use incremental costing is not acceptable to the Board. Full costing has been the general practice for programs that are not part of the core utility business and the Board sees no reason to deviate from that practice in this case. Full costing avoids cross-subsidization from gas to electricity ratepayers and reduces the incentive to shift resources from gas DSM to electric CDM in pursuit of possibly more lucrative returns in the latter.

Having approved the incentives contained in the "financial package", the Board does not see the need for other incentives necessary or appropriate for gas utilities to engage in electric CDM activities at this time.

CHAPTER 5 – INPUT ASSUMPTIONS, COMMON GUIDE, AND NEXT STEPS

In this chapter the Board addresses Issue 3.2 which is whether there should be a common guide to specify what input assumptions should be used by the utilities, and deals with the next steps of this proceeding.

Prior to and during the oral hearing the Board indicated that the process of listing and valuing input assumptions would not be part of this phase of the proceeding and that the Board wished to hear from parties on the appropriate subsequent process.

Issue 3.2 was phrased as, should there be a common guide (e.g. TRC Guide for Conservation and Demand Management ("CDM")) to specify what input assumptions should be used by the utilities?

All intervenors agreed as follows:

> "No. The input assumptions should be included in each utility's plan, and should be updated for each Utility during the plan period in accordance with the partial settlement to issue 3.1."

The utilities endorsed the notion of a common list and common values (where appropriate) of input assumptions for the two utilities in a common document. They suggested that this document would be an appendix to a Guide document which would reflect the Board's decision and convert elements of the decision into an operational handbook. They argued that this would be consistent with the intent of the proceeding to develop a rules-based framework for DSM. The utilities further suggested that Board Staff could take ownership of the development of the Guide and become the custodian for future updates.

The utilities argued that the creation of a common document has several advantages. Many of the input assumptions are common and they could be updated in their entirety by a Board process every three years. There would be no question as to the input assumptions that the utilities are to use. Assigning Board Staff the responsibility of updating the input assumptions would impart discipline on parties seeking to change the input assumptions. The utilities noted that where there was a need for different input assumptions between EGD and Union, it would not be difficult to effect within the list.

SEC argued that common input assumptions was a non-issue since the process for amending and updating the assumptions is completely settled in issues 3.1, 3.3 and 3.4 and that the existence of a guide is not relevant to the inclusion or determination of input assumptions. GEC endorsed SEC's view and further argued that an input assumptions process may frustrate the settlement on those issues. GEC further suggested that the Board should rely upon the evaluation and audit process to consider input assumptions. Energy Probe endorsed the submissions put forward by GEC and SEC. LPMA submitted that each utility should include its input assumptions as part of its own plan but the utilities should work together to develop common input assumptions where appropriate. Some argued that translating the Board's decision into a guide amounted to a waste of time, and unless the Board drafted the Guide and handed it to parties in a finished version, parties would take the opportunity to re-argue issues in interpreting the Board's decision.

In the Board's view it is clear that TRC input assumptions will have to be determined before any DSM plans can be finalized. The Board also agrees that the process should be conducted under the Board's review as a second phase to the current proceeding. The Board feels that the most appropriate process for creating the input assumptions guide is one similar to that employed to create the CDM Handbook. The Board therefore directs Board Staff to circulate a draft of an input assumptions guide. Parties will be given an opportunity to comment on the draft and, where they feel it necessary, to make submissions for changes with appropriate support. A Procedural Order will be issued which will set out the details of this process more fully. It is anticipated that this second phase to the proceeding will be completed before the end of 2006.

There are no persuasive reasons in the Board's view not to have a common list of input assumptions and common values with the exceptions of the values as noted in this decision. In fact it appears to the Board that there are efficiencies to be gained by the use of a common set of assumptions. To the extent that there may be differences in how the assumptions might apply to the two utilities or in the values themselves as allowed in the decision, these could be accommodated and highlighted within the generic set. There are only two gas utilities affected and it would not be administratively difficult to do so.

Once the initial list and measures of the input assumptions is determined, the issue then becomes: what is the process for updating these?

The completely settled issue 3.1 stipulates that the input assumptions will be updated on a regular basis during the plan period as part of each utility's ongoing evaluation and audit process. The Board has the ultimate authority to review and approve any changes. It appears to the Board that unless there is joint utility participation, the updates may occur at different times. This would not be efficient and would burden the regulatory process needlessly. The Board therefore concludes that the updating process should be centralized within Board Staff, at least for this first generation of multi-year DSM plans. The Board anticipates that the recommendations that come from the evaluation and audit committee would, in effect, be the substance of the comments process to be employed for the updating of the list and values of the input assumptions. Any suggested updates to the input assumptions guide arising from the evaluation and audit process should be filed with the Board within one month of the end of the annual audit and evaluation. The suggested updates will be considered by the Board, and the guide will be updated if the Board decides it is necessary. Further Procedural Orders may be issued regarding updates to the guide.

The next issue is whether there should be a handbook.

While the Board sees the merits in having a stand-alone handbook, it has concluded that this initiative should not be undertaken at this time. In making this finding, the Board is cognizant of the time sensitivity and significant effort that will be required to develop the common list and measures of the input assumptions and the Board does not wish parties be distracted by the effort to develop a handbook at this time.

The Board will issue a Procedural Order commencing the next phase that will lead into the determination of the input assumptions. The role of Board Staff will be set out in that procedural order. Further Procedural orders will be issued as required from time to time for the Board to receive and rule in this matter and to cause the filing of the multi-year DSM plans by the utilities.

Intervenors eligible for cost awards shall file their cost claims by September 15, 2006. The utilities may comment on these claims by September 22, 2006. The cost award applicants may respond to the utilities' comments by September 29, 2006. Union and EGD shall pay in equal amounts the intervenor costs to be awarded by the Board in a subsequent decision, as well as any incidental Board costs.

Dated at Toronto, August 25, 2006

Original Signed By

Pamela Nowina
Presiding Member and Vice Chair

Original Signed By

Paul Vlahos
Member

Original Signed By

Ken Quesnelle
Member

APPENDIX 1

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0021

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

PROCEDURAL DETAILS, LIST OF PARTIES AND WITNESSES

THE PROCEEDING

On February 15, 2006, the Board issued a Notice of Application that was published.

The Board issued Procedural Order No.1 on March 2, 2006, establishing the procedural schedule for all events prior to the oral hearing. These events included:

- EDGI and Union evidence filed by April 10, 2006;
- Issues conference on April 24, 2006;
- Issues Day on April 28, 2006;
- Technical Conference to replace interrogatories on EDGI and Union's evidence on May 11 and 12, 2006;
- Intervenor (non-utilities) evidence filed by June 1, 2006;
- Technical Conference to replace interrogatories on Intervenor (non-utilities) evidence on June 8, 2006;
- Half day Intervenor Conference on June 19, 2006;
- Settlement Conference beginning June 19, 2006;
- Settlement Proposal by June 28, 2006; and
- Board review of Settlement Proposal on July 6, 2006.

In response to Procedural Order No. 1, the Board received written evidence prepared by the following parties:

- Malcolm Rowan on behalf of Canadian Manufactures and Exporters ("CME");
- Paul Chernick on behalf of the School Energy Coalition ("SEC");
- Chris Neme on behalf of the Green Energy Coalition ("GEC"); and
- Roger Colton on behalf of Low Income Energy Network (LIEN").

On April 28, 2006, the Board issued Procedural Order No. 2, which established the Issues List for the proceeding.

On June 12, 2006, Procedural Order No. 3 was issued as a result of there not being adequate time to complete the questions on CME evidence within the one day Technical Conference. The Board ordered CME to provided written responses to SEC and GEC questions.

Procedural Order No. 4, issued June 28, 2006, provided the parties with an extension to file a Settlement Proposal with the Board.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board's offices.

Union Gas Limited ("Union")	Crawford Smith
Enbridge Gas Distribution ("EGD")	Dennis O'Leary
Board Counsel and Staff	Michael Millar Michael Bell Stephen McComb
Canadian Manufacturers & Exporters ("CME")	Brian Dingwall

Consumers Council of Canada ("CCC")	Robert Warren
Energy Probe	Norm Rubin
Green Energy Coalition ("GEC")	David Poch
Industrial Gas Users Association ("IGUA")	Vince DeRose
London Property Management Association ("LPMA")	Randy Aiken
Low Income Energy Network ("LIEN")	Juli Abouchar
Pollution Probe	Murray Klippenstein
School Energy Coalition ("SEC")	Jay Shepherd
Vulnerable Energy Consumer's Coalition ("VECC")	Michael Buonaguro

WITNESSES

There were 11 witnesses who testified at the oral hearing. The following EGD and Union employees appeared as witnesses at the oral hearing:

EGD

Susan Clinesmith	Manager, Business Markets
Norman Ryckman	Group Manager, Business Intelligence and Support
Michael Brophy	Manager, DSM and Portfolio Strategy
Patricia Squires	Manager, Mass Markets and New Construction Market Development

Union

Chuck Farmer	Director, Market Knowledge and DSM
Tracy Lynch	Manager, DSM

In addition, EGD called the following witness:

Dr. Daniel M. Violette	Principal and Founder, Summit Blue Consulting

Witnesses called by intervenors at the oral hearing:

Chris Neme (By GEC)	Director of Planning and Evaluation, Vermont Energy Investment Corporation
Malcolm Rowan (By CME)	President, Rowan and Associates Inc.
Roger D. Colton (By LIEN)	Consultant, Fisher, Sheehan & Colton

In addition, CME called the following witness:

Anthony A. Atkinson	School of Accountancy, University of Waterloo

K7.1

Ontario Energy Board   Commission de l'Énergie de l'Ontario

VT INCEPIT FIDELIS SIC PERMANET

Ontario

RP-2002-0158

IN THE MATTER OF APPLICATIONS BY

UNION GAS LIMITED

AND

ENBRIDGE GAS DISTRIBUTION INC.

FOR

A REVIEW OF THE BOARD'S GUIDELINES FOR ESTABLISHING THEIR RESPECTIVE RETURN ON EQUITY

DECISION AND ORDER

2004 January 16

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.1
DATE February 6, 2007
08/99

DocID: OEB: 13162-0

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2002-0158 1

EB-2002-0484

IN THE MATTER OF the *Ontario Energy Board Act*, 1998, S.O.1998, c.15, Schedule B; 2

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, transmission, distribution, and storage of gas; 3

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, transmission, distribution, and storage of gas; 4

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. and Union Gas Limited for a review of the Board's Guidelines for establishing their respective return on equity. 5

BEFORE: 6

Paul Vlahos 7
Presiding Member

Bob Betts 8
Member

Paul Sommerville 9
Member

DECISION AND ORDER 10

January 16, 2004 11

DocID: OEB: 13162-0

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1 THE APPLICATIONS AND THE PROCEEDING 14

The Applications 15

Union Gas Limited ("Union") filed an application for rates dated May 27, 2002 with the Ontario 16
Energy Board, under section 36 of the *Ontario Energy Board Act, 1998 S.O. 1998*, c.15, Schedule B (the "Act"). Union filed evidence in support of its application on June 25, 2002. The Board assigned file number RP-2002-0130 to Union's application. By letter dated August 1, 2002, Union added to its application a request for changes to the Board's formula used to establish Union's return on common equity ("ROE").

Enbridge Gas Distribution Inc. ("Enbridge" or "EGDI ") filed an application for rates dated 17
September 2, 2002, with the Board, under section 36 of the Act. Included in its application was a request for a change to the Board's formula used to determine EGDI's ROE. The Board assigned file number RP-2002-0133 to the EGDI application.

The Proceeding 18

The evidence in relation to the ROE issue relied upon by Union and EGDI in their applications is 19
essentially the same, and both Applicants rely upon the same consultant, Ms.K. McShane. With the consent of the Applicants, the Board decided to hear the ROE issue raised in the two applications in a separate stand-alone proceeding. The Board assigned file number RP-2002-0158 (EB-2002-0484) to this separate ROE proceeding.

On December 16, 2002, the Board issued Procedural Order No. 1 setting out the schedule for the 20
proceeding. In accordance with that order, Union filed on February 7, 2003 updated evidence prepared by Ms. McShane.

Procedural Order No. 2 issued on March 3, 2003 amended the dates for the proceeding as follows: 21
interrogatories on the Applicants' evidence were due on April 11, 2003; interrogatory responses were due on April 29, 2003; supplementary interrogatories on the Applicants' evidence was due on May 8, 2003 and responses to supplementary interrogatories, were due May 15, 2003; an Issues/ Technical Conference was to be held on May 21, 2003; an Issues Day proceeding was to be held on May 23, 2003; intervenor evidence was to be filed by June 27, 2003; interrogatories on intervenor evidence were due by July 11, 2003; interrogatory responses were due by July 25, 2003.

Procedural Order No. 3 issued on April 30, 2003 cancelled the Issues/Technical Conference and the 22
Issues Day and specified that a Stakeholders Conference take place on May 23, 2003. Procedural Order No. 4 issued on July 3, 2003 set the commencement of the hearing as September 18, 2003. On August 12, 2003 the Board issued Procedural Order No. 5 which revised the hearing date to September 22, 2003.

The Hearing 23

The oral proceeding commenced on September 22, 2003, and concluded on September 26, 2003 after 5 hearing days. 24

The Applicants filed their written argument-in-chief after the close of business October 20, 2003, rather than October 17, 2003 as originally scheduled. Consequently, some intervenors requested a corresponding extension to file their reply argument, which the Board granted. Six intervenors filed their arguments by November 5, 2003. The Board also extended the date on which the Applicants' reply argument was due from November 7, 2003 to November 12, 2003. At the request of the Applicants, the Board further extended the filing date from November 12 to November 21, 2003. 25

Parties and their Representatives 26

Below is a list of parties and their representatives who participated actively by leading evidence or cross-examining witnesses in the oral hearing, or by filing argument. 27

28

Union Gas Limited	Michael Penny Marcel Reghelini
Enbridge Gas Distribution Inc.	Helen Newland Marika Hare
Board Counsel	Patrick Moran
Consumers Association of Canada ("CAC")	Robert Warren
London Property Management Association ("LPMA")	Randy Aiken
Industrial Gas Users Association ("IGUA")	Peter Thompson
Vulnerable Energy Consumers Coalition ("VECC")	Michael Janigan
Energy Probe	Brian Dingwall
Pollution Probe	Murray Klippenstein
Ontario Public School Boards' Association ("OPSBA")	Jay Shepherd
Canadian Gas Association ("CGA")	Laurie Smith

Witnesses 29

The Applicants called the following witness: 30

Kathleen McShane	Senior Vice President, Foster and Associates

IGUA/VECC/CAC called the following witness: 31

Lawrence Booth	Professor of Finance, Rotman School of Management, University of Toronto

32

33

CGA called the following witnesses:

Peter Case	Peter Case Consulting
Michael Cleland	President and Chief Executive Officer, Canadian Gas Association

The Board called the following witness: 34

William Cannon	Associate Professor of Finance, School of Business, Queen's University

Submissions and Exhibits 35

Copies of the evidence, exhibits, arguments, and a transcript of the proceeding are available for review at the Board's offices. 36

The Board has considered the evidence, submissions and arguments in the proceeding, but has summarized the evidence and the positions of the parties only to the extent necessary to provide context for its findings. 37

The Board, with industry participation, has developed standards and processes for the electronic regulatory filing ("ERF") of evidence, submissions of parties, Board orders and decisions. This Decision and Order will be available in ERF form shortly after initial copies are issued in hard copy. The ERF version will have the same text and numbered headings as the initial hard copy, but may be formatted differently. 38

2 SUMMARY OF CURRENT GUIDELINES 39

The Ontario Energy Board currently uses a formula based approach to set the return on common equity ("ROE") for most gas utilities under its jurisdiction. The Board's approach is set out in its *Draft Guidelines on a Formula-Based Return on Common Equity* ("ROE Guidelines"). The ROE Guidelines were first applied in the EBRO 495 proceeding which set fiscal 1998 rates for The Consumers' Gas Company Ltd. (now EGDI). 40

The ROE Guidelines start with the establishment of a benchmark ROE to provide, as it was described in the EBRO 495 decision, "a just and reasonable return on equity" for each gas distribution company. This benchmark ROE is then adjusted for each subsequent fiscal year in accordance with an adjustment mechanism. 41

The benchmark ROE for a utility is set by taking the forecast yield for long-term Government of Canada bonds and adding an appropriate risk premium to account for the utility's risk relative to the long-term Government of Canada bonds. The equity risk premium test is used to determine the appropriate risk premium. 42

The Compendium to the ROE Guidelines, at p.5, described this method as follows: 43

> The equity risk premium test is also designed to measure the cost of equity capital from the capital attraction perspective. It relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk. The premium required by an investor to assume the additional risk associated with an equity investment is taken to be the difference between the relevant debt rate, usually the yield on long-term government bonds, and some estimate of the stock's cost of equity. The recommended cost of equity value under the equity risk premium approach is therefore usually computed as the sum of the test-period forecast for the government yield and the utility-specific risk premium the analyst has estimated based on historical equity risk premium evidence and forward-looking considerations. 44

The benchmark ROE becomes the allowed ROE for the first year. EGDI's benchmark ROE was set at 10.65% in the EBRO 495 proceeding, based on a risk premium of 340 basis points. Union's benchmark ROE was set at 11.00 % in the EBRO 493-04/494-06 proceeding, based on a risk premium of 355 basis points. The 15 basis points difference reflects the relative risk of the two utilities. The difference of the returns over 15 basis points is accounted for by the difference in the timing of setting the rate or return for the two utilities. 45

Once the benchmark ROE has been established, the allowed ROE is automatically adjusted annually, using a formula. The change in the forecast yield for long-term Government of Canada bonds is multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. This adjustment 46 factor is then added to the utility's previous test year ROE and the sum is rounded to two decimal points to produce the new ROE.

47

Example:

Allowed ROE for test year 1		10.00%
Test year 2 long-term Government of Canada bond yield forecast	5.00%	
Test year 1 long-term Government of Canada bond yield forecast	5.25%	
change in interest rates	-0.25%	
adjustment factor of 0.75 applied		0.1875%
ROE for test year 2		9.8125%
Approved ROE for test year 2 (rounded to 2 decimal places)		9.81%

Regarding the need for review in the future, the ROE Guidelines, in the Compendium at p. 28, state: 48

49

> The Board believes that the rate of return formula should be reviewed as conditions arise that may call into question its validity (e.g., a change in the relative taxation of the income from debt and equity investments, or a fundamental change in business or financial market conditions). To set a particular time period may be artificial and necessitate an unnecessary review or stifle a review at another time when an adjustment would be appropriate. Parties to a proceeding may ask the Board to review the formula when they feel it is appropriate or the Board may do so on its own initiative. In either case it will be the Board's decision as to the time for a review.
>
> From time to time the Board may request the presentation of other tests or require some weighting for other tests in the formula should the Board want to assure itself that the equity risk premium formula approach does not lead to perverse results and is directionally in line with other market indicators.

3 EVIDENCE AND POSITIONS OF THE PARTIES 50

The Applicants 51

The Applicants relied on Ms. McShane's evidence, in support of their request for a new benchmark ROE and a change to the annual adjustment formula. 52

Ms. McShane concluded that the ROE Guidelines produce an ROE for EGDI and Union that is unreasonably low. This conclusion was based upon her proposed methodology, her analysis of changes in the Canadian bond market since March 1997, and her consideration of the allowed returns for U.S. gas and electric utilities. 53

To formulate her recommendation for a new benchmark ROE in the range of 11.5 - 11.75%, based on a forecast 6.0% yield for long-term Government of Canada bonds, Ms. McShane applied three equity return tests; the Equity Risk Premium (ERP) test, the Discounted Cash Flow (DCF) test and the Comparable Earnings (CE) test. 54

Ms. McShane used three versions of the ERP test which produced an ROE range of 10.5% to 11.25%. 55

Ms. McShane's DCF test, which she applied exclusively to a sample of U.S. utilities, produced an ROE of 11.5%. 56

Ms. McShane applied her CE test to both Canadian and U.S. industrial returns covering the 1992-2001 period, and giving primary weight to the Canadian evidence, this produced an ROE range of 12.75 - 13.25%. 57

Ms McShane then combined these results, weighting the ERP and DCF test results 37.5% each, and the CE test results 25%, to produce her recommendation that an appropriate benchmark ROE would be in the range of 11.5 - 11.75% for an average risk utility. She recommended the mid-point of 11.625% as an appropriate benchmark ROE for Union, as an average risk utility, and 11.5% for EGDI, as a slightly lower risk utility. 58

Ms. McShane noted that the regulated ROE for U.S. gas and electric utilities were typically higher than for utilities in Canada. She was of the view that this divergence could disadvantage Canadian utilities and their shareholders within the context of an increasingly integrated North American capital market environment. 59

Ms. McShane also pointed to a number of changes that had occurred in the bond and equity markets after the ROE Guidelines were established, which she relied on to support her contention that the risk premiums used to set the original benchmark ROE for the Applicants are too low in today's context. 60

CGA 61

The CGA sponsored the evidence of Mr. Cleland and Mr. Case. Mr. Cleland was presented as a policy spokesperson for the CGA and his evidence was limited to confirming that the CGA supported a higher ROE for Canadian utilities, including the Applicants. 62

Although Mr. Case did not propose any changes to the current ROE formula or the annual adjustment mechanism, his view was that an ROE in the range of 10.5 - 11.0% would be viewed by equity markets as a fair return, based on his telephone discussions with various equity market participants and analysts. 63

His recommendation was based on the following five factors. 64

First, Mr. Case claimed that the formula no longer compensates investors appropriately for an increase in the perceived riskiness of utilities since 1997. 65

Second, according to Mr. Case, recent market conditions limit the usefulness of the Capital Asset Pricing Model (CAPM) because market conditions have artificially depressed utility stock betas. 66

Third, he suggested that the continuing globalization of capital markets since the Board issued its 1997 ROE Guidelines has made a comparison to higher US utility returns more relevant. The lower returns of Canadian utilities put them at a competitive disadvantage in attracting capital. Mr. Case pointed to the recent sale by Aquila Inc. of its Canadian utility as an example of an investor not willing to invest in a utility in British Columbia or Alberta because the ROE was too low. He also pointed to some examples of Canadian utility holding companies that experienced difficulty in raising common equity as a further demonstration that the current level of ROE for Canadian utilities was a problem. 67

Fourth, with the significant decline in bond yields since 1997, the formula has resulted in a decline in equity returns that is faster than the decline in the utilities' embedded cost of debt. As a result, there has been downward pressure on utility interest coverage ratios, which in turn puts pressure on utility debt ratings. 68

Finally, Mr. Case believed that the majority of institutional equity investors view the returns currently generated by the formula based approach used by the Board and other Canadian regulators as inadequate. 69

CAC, IGUA and VECC 70

CAC, IGUA and VECC sponsored the prefiled report prepared by Drs. Booth and Berkowitz. The authors concluded that a fair ROE for the Applicants is in the range of 8.5%, which includes a 50 71 basis point "cushion" above their estimates of the cost of attracting capital for these utilities. Only Dr. Booth testified in the hearing but he adopted the joint prefiled evidence.

In their report, Drs. Booth and Berkowitz came to their ROE recommendation by applying two versions of the ERP test and giving equal weight to the results. Their first ERP test was the single-factor Capital Asset Pricing Model (CAPM), while their second ERP test relied on a two-factor model which differentiated between the systematic risk due to changes in the equity market and changes in security returns due to fluctuations in interest rates. 72

Their application of the CAPM model yielded an ROE in the range of 8.02% to 8.47%. This was based on their assessment that (1) the market risk premium is now 4.5% and (2) a reasonable range for the beta risk of an average-risk regulated Canadian utility is 0.45 to 0.55. 73

Applying their two-factor model, which incorporates a term premium estimate of 1.00%, produced an ROE in the range of 7.66% to 7.74%. 74

In further support of their proposed benchmark ROE of 8.5%, Drs. Booth and Berkowitz produced DCF test results, based on a sample of U.S. utilities, that pointed to an ROE in the range of 7.89 to 8.57%. 75

In testimony, Dr. Booth indicated that he did not see a need to move away from the Board's ROE Guidelines, even though their analysis suggested that the ROE Guidelines produced an ROE that was more generous than it needed to be. In their report, Drs. Booth and Berkowitz stated their belief that the 75% adjustment factor was a reasonable compromise between (a) assuming that the overall required return on the stock market is independent of long-term Government of Canada bond yields implied by a 50% adjustment coefficient, and (b) assuming that the riskiness of the long-term Government of Canada bond relative to the equity market is constant, as implied by a 100% adjustment factor. 76

Finally, Drs. Booth and Berkowitz pointed out that the market-to-book-value ratios of all Canadian utilities, save one, were well in excess of 1.0. They stated that this was a clear indication that utilities have not suffered a loss of financing flexibility since Canadian regulators moved to automatic ROE adjustment mechanisms based on long-term Government of Canada bond yields, beginning in 1994. 77

Dr. Cannon 78

Dr. Cannon was retained by the Board to provide additional evidence on the ROE issues. He prepared a report that was provided to all parties and he answered interrogatories on his evidence. He also appeared as a witness and was cross-examined by the parties. His expert opinion, as with the other expert witnesses, was provided to the Board entirely on the public record. 79

In his evidence Dr. Cannon concluded that there had been a substantial decline in the equity capital costs for the average-risk Canadian gas utility and for Ontario's major gas distributors since 1996. 80

According to Dr. Cannon, there is no evidence to suggest that the application of the Board's ROE formula methodology had resulted in allowed returns which had violated either the fair return or financial integrity standards of regulatory rate setting. 81

He also submitted that the decrease in ROE under the ROE Guidelines had been less than it would have been, applying the capital attraction standard of regulatory rate setting instead. 82

It was Dr. Cannon's view that an appropriate benchmark ROE for the average-risk Canadian energy utility now lies in the range of 7.5% to 7.9%, lower than the ROE that would currently be produced under the ROE Guidelines. Dr. Cannon's benchmark ROE recommendation is based primarily on results from using the three equity return tests that Ms. McShane used. In using those tests, he applied different judgment and reached different conclusions than Ms. McShane did. 83

Using his ERP test, Dr. Cannon concluded that an appropriate ROE would be in the range of 6.35-6.55% for the average-risk Canadian energy utility, based on a mid-June estimate of 4.00% for the yield on a truly riskless long-term Canadian asset and a corresponding "all-in ERP" in the 2.35-2.55% range. His utility ERP test findings reflected the substantial decline in the prospective market risk premium in recent years as well as the continuing low relative investment riskiness of the typical energy utility. 84

Applying the DCF test to a sample of Canadian energy utilities produced a benchmark ROE in the range of 7.9% to 8.5%. 85

The CE test, using data for Canadian industrials over the 1991-2002 period produced an ROE of 10.2% for Dr. Cannon. 86

To arrive at his final recommendation for a benchmark ROE, Dr. Cannon applied different weights to his three test results than Ms. McShane. Dr. Cannon weighted his results from the three tests as follows: ERP - 60%, DCF - 15%, and CE - 25%. 87

Dr. Cannon's ROE recommendation reflected an "all-in benchmark ERP" of 2.93% above the long-term Government of Canada bond yields prevailing in mid-June. 88

With respect to the adjustment formula, Dr. Cannon proposed that the adjustment factor applied to changes in the forecast long-term Government of Canada bond yields be reduced to 70%, from the current 75% value. He based this on his view of the sensitivity of his equity return tests to changes in the long-term Government of Canada bond yields and his weighting of the three tests. 89

Dr. Cannon concluded that, all other things being equal, the ROE numbers produced by the ROE Guidelines in recent years are likely too high. 90

LPMA 91

LPMA did not rely on the evidence of any particular expert as, in its opinion, the analysis of any one expert did not produce a definitive estimate of a fair return. Instead, LPMA gave equal weight to the results of the work done by Ms. McShane, Dr. Cannon and Drs. Booth and Berkowitz, with one exception. LPMA argued that zero weight should be given to Ms. McShane's CE test because, in the view of LPMA, the market risk premium was overstated. 92

LPMA's final recommendation for a new benchmark ROE was 8.96% based on giving equal weight to the three expert's evidence, removing the CE test, applying a market risk premium of 325 basis points, and averaging the three ERP estimates produced by Ms. McShane, Dr. Cannon and Drs. Booth and Berkowitz. 93

LPMA submitted that the CE test should not be relied on because of the difficulty in assembling an acceptable sample of comparable companies against which to assess the regulated utility. First, LPMA noted that both Dr. Cannon and Ms. McShane selected comparable industrials yet the results were 300 basis points apart. Second, there had been debate regarding the appropriate earnings to use and widespread concern regarding corporate reporting which placed the accuracy of the information in doubt. Third, the American returns were not suitable comparators as the American economy was generally more competitive resulting in higher risks and consequently higher returns. Fourth, LPMA noted that Canadian regulators often gave little or no weight to the CE test. 94

School Boards 95

School Boards also did not call any evidence. School Boards recommended that the Board approve an ROE of 9.0% for EGDI, assuming a risk-free rate of 5.4%. 96

With respect to Union Gas, School Boards believed that there was no evidence to suggest that Union Gas was any riskier that EGDI. The premium paid by Duke when it acquired Union suggested that Union was not as risky as Ms. McShane or Dr. Cannon believed. Further, the fact that the two utilities are at the same deemed equity ratio implied that they could be considered to be at the same risk level. Therefore, School Boards submitted that the Board should approve an ROE of 9.0% for Union Gas as well. 97

School Boards noted that the debate of the experts demonstrated that the same underpinning numbers could produce different results. Therefore the expert evidence was suspect, as all of the experts chose and manipulated data in ways that limited the objectivity of their conclusions. The School Boards argued that, given this uncertainty among experts regarding the appropriate ROE tests, greater weight should be placed on evidence other than that of the experts. 98

School Boards' position was therefore not tied to that of the experts. Instead it proposed a different approach. School Boards proposed five tests to arrive at its 9.0% ROE recommendation. 99

The first test, named the "mind experiment", consisted of arriving at a number representing the intersection of the experts' broadest ranges of ROE. 100

The second test, using the Seigel Tables, implied a long term market return for utilities of 7.56% to 7.74% if compound returns were used. If arithmetic mean returns were used, then the resulting ROE would be in the range of 8.46% to 8.72%. 101

The third test, based on expectations of pension funds, suggested that utility ROE should be no more than 8.5%. 102

The fourth test, the premium paid by Duke, Union's parent company, demonstrated that the current ROE resulting from the formula was somewhat high. According to School Boards, assuming that the current ROE was too high by 50 basis points, the resulting ROE would be 8.76 for EGD and 8.91% for Union Gas. 103

The fifth test, a simple average of the experts' recommendations, resulted in an ROE of 9.05%. 104

Combining these five approaches led School Boards to recommend a new benchmark ROE of 9.0% for both Applicants. 105

With respect to the adjustment mechanism, the School Boards supported the proposal of the Applicants to adjust the ROE annually by 50% of the change in the forecast long-term Government of Canada bond yields. 106

Energy Probe 107

Energy Probe also did not rely on the evidence of any particular expert. It submitted that there was no need to make any changes to the ROE Guidelines and that the ROE Guidelines should be re-affirmed to signal stability and predictability in Ontario's natural gas environment. 108

Energy Probe submitted that there was no evidence that the Applicants had suffered any capital shortage under the current ROE Guidelines. In fact, the formula seemed to provide adequate consideration of costs related to maintaining access to capital markets. Furthermore, it was not necessary to make changes to the ROE formula to address changes to business and financial risk because other mechanisms, such as deferral accounts, were available to the Board for this purpose. 109

Energy Probe suggested that the actual financial performance of utilities demonstrated that they were low risk enterprises and that the argument for any alteration to the ROE formula was weak. Energy Probe noted that over the last decade, both utilities had consistently outperformed the Board allowed ROE. 110

Pollution Probe 111

Pollution Probe did not address the issue of the appropriate ROE formula. Rather it requested that the Board permit the Applicants to earn an additional ROE, over and above what the ROE Guidelines would produce, as an incentive to aggressively promote cost effective energy conservation and efficiency. 112

113

4 BOARD FINDINGS

The Board's ROE Guidelines suggest that there are two reasons which would justify a review of the formula. The first justification would be significant changes in market conditions. The second justification would be significant changes in the utility risk. The Applicants have based their request for a review on their assertion that there have been significant changes in the capital markets. There is no claim that the utility risk per se has increased. The Board recognizes that the ROE Guidelines are not binding and that it is always open to a party to propose a new approach. The Applicants have made such a proposal and the Board has considered on its merits. 114

The first issue for the Board is whether the adjustment mechanism contained in the current ROE Guidelines produces a prospective return on common equity that continues to be appropriate. The formula in the current guidelines produces an ROE of 9.71% for Enbridge and 9.86% for Union at a long-term Government of Canada bond yield of 6.00%. This reflects a risk premium of 371 basis points for Enbridge and 386 basis points for Union. At a long-term Government of Canada bond yield of 6.00%, the Applicants are asking the Board to set a new benchmark ROE of 11.50% for Enbridge and 11.65% for Union. This proposal reflects an increase in the risk premium to 550 basis points for Enbridge and 565 basis points for Union. They are asking the Board to move from sole reliance on the equity risk premium (ERP) test, as set out in the ROE Guidelines, to weighted reliance on three tests described in Ms. McShane's evidence: the ERP test (37.5%), the discounted cash flow (DCF) test (37.5%) and the comparable earnings (CE) test (25%). 115

The second issue for the Board is the Applicants request, based on Ms. McShane's evidence, for a change to the annual adjustment formula, so that in each succeeding year, the ROE is adjusted by 50% of the change in the forecast yield for long-term Government of Canada bonds, rather than the 75% required by the ROE Guidelines. However, this request was contingent upon the outcome of the first issue. 116

The third issue for the Board is the request by the Applicants, based on Ms. McShane's evidence, that the factor representing the yield spread between the 10 and 30 year Government of Canada bonds be fixed, rather than being calculated annually. Dr. Cannon makes the same suggestion, although he recommends a lower spread than Ms. McShane. 117

First, we will deal with the primary issue of whether a new benchmark ROE should be established for EGDI and Union. 118

In approving or fixing rates, the Board derives its jurisdiction from section 36 of the Act. Pursuant to that section, the Applicants can only charge rates for the distribution of gas with the approval of the Board. The burden of proof to demonstrate that the rates applied for are just and reasonable lies with the Applicants. The setting of just and reasonable rates involves the balancing of the interests of the Applicants, on the one hand, and the ratepayers, on the other hand. Rates will be just and reasonable when the ratepayers are paying a fair price for the distribution services that they receive and the Applicants have an opportunity to earn a fair return on their invested capital. Allowance for 119 a prospective fair return on common equity is therefore a component of establishing just and reasonable rates.

Section 36 (3) of the Act provides that the Board can adopt any method or technique for the setting of rates that it deems appropriate. The method to be adopted is at the Board's discretion, which the Applicants, the expert witnesses and other parties acknowledge. Currently, for the purpose of establishing the ROE for a utility, the Board uses a formula based approach, as set out in the ROE Guidelines, based on the ERP test. The institution of this formula and its application dates back to 1997. None of the parties have proposed that the Board should move away from a formula based approach. We are of the view that it is appropriate to continue with a formula based approach because it provides a significant degree of predictability and is compatible with both cost of service and performance-based regulation. 120

A great deal was made in the hearing by Ms. McShane and the Applicants about comparisons with American utilities and returns awarded by other Canadian jurisdictions. The Applicants argue that the returns of American utilities are higher and that this supports the need for higher returns for the Applicants. They also cite decisions by certain Canadian regulators in support of higher returns. Yet, they also argue that the Board should not be influenced by the unfavourable decisions for recalibrating the existing formula by certain other Canadian regulators, on the basis that this Board should lead rather than follow. Also, they state that the Board must consider the applications on their own merits. 121

Discussions of ROE decisions from other jurisdictions invariably come into the evidence and arguments of parties. We continue to view such evidence as informative. However, we do not believe that decisions in other jurisdictions are determinative of what ought to be a prospective fair ROE for Ontario utilities. There are many reasons why ROE may differ from one jurisdiction to another in North America. These may include differences in legislation, timing, tax laws, accounting practices, risk considerations arising from different capital structures and from regulatory practices which may or may not shield the utility from business or weather risks, and other regulatory considerations unique to each jurisdiction, including varying reliance on the common tests for determining a fair ROE. There was no evidence that would allow the Board to make a meaningful comparison of these factors, including the relative riskiness of Canadian and American utilities, in order to understand the difference in ROE between American and Canadian utilities. The bare fact that American utilities might earn a higher ROE than Canadian utilities, as suggested by Ms. McShane and argued by the Applicants, is an inadequate basis upon which to determine whether the ROE for the Applicants should be increased to a level similar to the ROE for American utilities. Similarly, the fact that some Canadian regulators may have awarded higher or lower returns than the Ontario Energy Board, while informative, is not determinative for largely the same reasons. 122

Ms. McShane suggested that the difference in ROE between American and Canadian utilities was a factor that could create a disadvantage for Canadian utilities and their shareholders. However, we find no evidence to suggest that such a disadvantage currently exists or is likely. Mr. Case suggests that Union, for example, must now compete for equity capital with the other global subsidiaries of Duke Energy, Union's parent; if Union cannot offer a competitive return with the other units, capital might be more difficult to obtain from the parent company. There was no evidence before the Board to suggest that the Applicants are experiencing any difficulty in raising equity capital from or through their respective parents. 123

A long standing regulatory principle espoused by the Ontario Energy Board, and by other regulators in North America, is the stand-alone principle. Applying this principle, the issue is what ought to be a prospective fair return on investment for a utility on a stand-alone basis, and not how a prospective return may compare or compete with other business units of the parent company. Should it be the case that the Ontario gas utilities are unable to attract equity capital by virtue of competition at the parent company level, whether the parent company is foreign or domestic, this would be of great concern to the Board. 124

There was no evidence before the Board to suggest that Canadian utilities in general were experiencing difficulty in raising capital, or doing so at unreasonable terms. Mr. Case mentioned that BC Gas had difficulty raising equity; the equity issue "sat on the shelf" until the dealers were willing to discount it. Dr. Booth countered this point by explaining that the reason that the equity issue sat on the shelf was due to the fact that there was a bidding war amongst investment dealers due to a shortage of such deals at that time. The winning dealer paid a premium for the equity issue in order to secure the underwriting fees. Dr. Booth suggested that this example was in fact a demonstration of how easily a utility could raise capital. 125

Mr. Case pointed to the recent sale of a Canadian pipeline utility by Aquila Inc. as an example of an investor unwilling to invest in Canada. However, the evidence revealed that Aquila was able to sell its pipeline utility to Fortis Inc. at a considerable premium, which would suggest that there are investors willing to invest in Canadian utilities. There was no evidence that Aquila Inc. sold its utility because of concern of the ROE earned by that utility. In fact, the evidence reveals that utility ownership transfers in recent history have taken place at above book value. While there may be many reasons that a company may be willing to pay more than book value for utility assets, there was no evidence to suggest that investors are deterred from investing in Canadian utilities because of inadequate prospective returns. 126

We found no evidence of the Applicants being in financial hardship as a result of the authorized ROE. The Applicants confirmed that they continue to be responsible for raising their own debt capital. There was no evidence, for example, that the allowed ROE has resulted in inadequate financial ratios to preclude raising debt capital on reasonable terms. Similarly, there was no evidence before the Board to suggest that credit ratings of the Applicants were deteriorating. The evidence is that the Applicants enjoy favourable credit ratings. In fact, Union's credit rating is more favourable than its parent company. 127

Mr. Case made references to changes in the business risk faced by the Applicants, but that issue was not before the Board. The Applicants made their request for a change in ROE based on the capital markets and not on any financial or business risk that they were facing. Ms. McShane confirmed in responding to questions that business and other risks covered by the equity component of capital structure were not matters at issue in this hearing. The Applicants did not dispute this testimony. 128

Having found no evidence of returns being inadequate so as to jeopardize the financial and operational aspects of Enbridge and Union, the issue then is whether the rate of return resulting from the equity risk premium test under the current ROE Guidelines is appropriate. 129

Three tests, and their variants, were employed or critiqued by the experts. All three witnesses had varying views with respect to the appropriateness of relying on the ERP test, the DCF test and the CE test. This was a large contributor to the differences between their recommendations. The other large contributor to the difference was the results arrived at by employing the same tests. The evidence of Ms. McShane, Dr. Booth and Dr. Cannon makes it clear that a great deal of judgment is involved in determining what is an appropriate ROE for a utility. Those three witnesses, along with Mr. Case, were looking at the same capital markets but came up with significantly different recommendations to the Board. However, Dr. Booth and Dr. Cannon also conceded that the current ROE Guidelines were still generally appropriate, despite their recommendations for a lower benchmark ROE. Ms. McShane was more categorical in her view that the ROE Guidelines were no longer producing a fair ROE and that a new benchmark ROE and adjustment formula were needed. 130

On the basis of the evidence adduced in this proceeding, we find that the reservations the Board expressed in the compendium to the current ROE Guidelines about the CE and DCF approaches and the Board's decision not to employ these tests remain valid. With respect to the CE test, we continue to be concerned with the problems associated with the assembling of an acceptable list of comparable companies against which to assess the regulated utility, as well as the selection of a suitable time period from which to draw historical evidence. We note that the subjectivity involved in the selection of an appropriate sample of comparators and the selection of the time period were the primary factors in arriving at an ROE difference of 300 basis points between Ms. McShane and Dr. Cannon. We also reiterate our concern with this test's heavy reliance on past performance as an indicator of future performance. 131

With respect to the DCF test, we note the sensitivity of the results to assumptions, including growth estimates. We note that as a result of different assumptions, Ms. McShane's ROE result from the DCF test is over 200 basis points higher than the results obtained by Dr. Booth and Dr. Cannon. Further, in the context of the specific applications before us, we remain uncomfortable with the results of the DCF test given that the shares of the Applicants are no longer traded on the open market. 132

As a result of the above, we reiterate the Board's conclusions reached when it developed the existing ROE Guidelines that the results from the CE and DCF tests should be given little or no weight for purposes of these applications. 133

We do not accept the suggestions by certain parties to use the approach of averaging the recommendations or to embark on tests that do not have theoretical foundation. Therefore for the purposes of this proceeding we will rely primarily on the results of the ERP test. Other than Mr. Case, all expert witnesses used this test. 134

There are four basic components to this test: a determination of the risk-free rate; a determination of the equity risk premium for the market as a whole; an adjustment (beta) to reflect the lower risk of utilities; and an allowance for financial flexibility or "cushion". Supplemental analysis to the basic ERP test was performed by Ms. McShane and Drs. Booth and Berkowitz. 135

No party has disputed the use of the long-term Government of Canada bond yield as the basis of the risk free rate, or the basis for its forecast as contained in the current ROE guidelines other than the 136 suggestion to fix the spread between the 10 and 30 year bond yields. Also, there was no dispute about the 50 basis points cushion. The disputes are around the determination of the market risk premium and the risk adjustment to reflect the lower risk for utilities.

137 Ms. McShane calculates a market risk premium of between 600 and 650 basis points. Dr. Booth calculates the premium at about 450 basis points and Dr. Cannon at about 350 basis points. The recommendations of a benchmark return under the basic ERP test of about 400 basis points for Ms. McShane, about 200 basis points for Dr. Booth, and about 160 basis points for Dr. Cannon reflect their choice of a relative risk adjustment of 0.60-0.65, 0.45-0.55, and 0.45, respectively. Adding the 50 basis points of cushion, the recommended benchmark equity risk premium under the basic test for Ms. McShane is 450 basis points, for Dr. Booth 250 basis, and for Dr. Cannon 210 basis points.

138 On the basis of the record adduced in this proceeding, we are of the view that Dr. Cannon's result is too low and Ms. McShane's too high. We find that the record reasonably supports a risk premium for the market as a whole between 500 and 550 basis points. We note from the evidence that the Alberta Energy and Utilities Board which recently reviewed similar data concluded that the market premium is 525 basis points. This is the mid-point of our 500 to 550 range. Using this mid-point figure, and without any modifications to Ms. McShane's recommended risk adjustment, one would obtain an overall equity risk premium of about 375 basis points, inclusive of the 50 basis points cushion. These equity risk premiums compare with 371 basis points for Enbridge and 386 basis points for Union under the current ROE Guidelines. Ms. McShane's recommended risk adjustment is higher than the other experts. A lower risk adjustment than that recommended by Ms. McShane would result in the equity risk premium under the current formula being favourable to the Applicants.

139 Ms. McShane used two other tests under the risk premium method, both utilizing utility data only. The first was the DCF based equity risk premium test, which produced an equity risk premium of 460 to 470 basis points. For the reasons outlined in the discussion of the DCF approach above, and our observation that the results indicate a much higher equity risk premium than the basic test produces, we place little or no weight on these results.

140 The second is a historic test, using data from both Canadian and American utilities. This test produced an equity risk premium of 475 to 500 basis points. We similarly place little or no weight on these results. We are not comfortable with the circularity that is inherent using regulated utility data, and the inclusion of American utilities which may bias the results without a thorough understanding of the justification for the higher returns of these utilities.

141 We conclude that not only does the equity risk premium formula approach not lead to perverse results, but that the results it currently provides continue to represent fair and reasonable returns. If we had to set a new benchmark rate of return based on the ERP evidence in this proceeding, this rate would not be materially different from that produced by applying the current formula.

142 Therefore, with respect to the first and primary issue of whether a new benchmark ROE should be established for EGDI and Union, we find that the current ROE Guidelines methodology continues to produce appropriate prospective results. We have not found any demonstrated need to set a new benchmark ROE.

Given this finding, the second issue, the Applicants' request for the annual ROE adjustment to be decreased to 0.50 from 0.75 of the change in the forecast yield for long-term Government of Canada bonds, is moot. 143

As for the third issue, the suggestion that the factor representing the yield spread between the 10 and 30 Government of Canada bonds be fixed rather than being calculated annually, the Board does not consider this to be of sufficient consequence, by itself, to justify a change to the existing guidelines. 144

Accordingly, based on the foregoing findings, the Board orders that the applications are dismissed. 145

In making this determination, the Board also considered the proposal put forward by Pollution Probe to increase ROE as an incentive to promote cost effective energy conservation and efficiency. The Board notes that the Applicants currently have demand side management programs in place that have already been ruled upon. This proceeding is focussed on whether conditions in the capital markets warrant a change to the Board's formula based approach to setting the ROE for the Applicants. The Board also notes that Pollution Probe and the Applicants are participating in a broad Board initiative that is examining energy conservation and efficiency. 146

The Board will issue a separate decision on cost awards. 147

DATED at Toronto January 16, 2004 148

On behalf of the Hearing Panel

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Paul Vlahos
Presiding Member

K7.2

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February 2, 2007

Ontario Energy Board	
FILE No.	EB-2006-0034
EXHIBIT No.	K7.2
DATE	February 6, 2007
08/99	

Fred Cass
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Dear Mr. Cass

Enbridge Gas Distribution Inc. 2007 Rate Case
OEB File No.: EB-2006-00034
Our File No.: 302701-000398

The purpose of this letter is to provide EGD's Cost of Capital Witness Panel with advance notice of our intent to ask questions about the impact of EGD's overall depreciation rate of about 4.56% (see Exhibit D, Tab 13, Schedule 1, page 3, line 7, column 4) on EGD's interest coverages compared to the overall depreciation rates for other utilities such as Union Gas Limited ("Union") of about 3.3% and TransCanada PipeLines Limited ("TCPL") of about 3.42%.

We are enclosing with this letter a copy of excerpts from the National Energy Board's ("NEB") Reasons for Decision in RH-1-2002 dated July 2003 wherein the NEB established TCPL's composite depreciation rate at about 3.42%. We are also enclosing copies of Exhibit D3, Tab 4, Schedule 1 in Union's 2007 Rate Case which shows its provision for depreciation which we calculate to be about 3.3%.

EGD's composite depreciation rate of 4.56% exceeds that of Union and TCPL by at least 1.14%. We estimate that the component of EGD's 2007 revenue requirement attributable to depreciation is about $60.4M higher than it would be if EGD's depreciation rate were comparable to that of Union and TCPL (EGD's depreciable plant of $5,294.9M shown at Exhibit D1, Tab 13, Schedule 1, page 3, line 6, column 2 multiplied by 1.14% = $60.36M).

Compared to Union and TCPL, EGD's favourable depreciation rate provides it with enhanced interest coverage calculated on an Earnings Before Depreciation and Income Taxes basis.

We will also be noting the incompatibility between EGD's composite depreciation rate of 4.56% and the revenue horizon assumption for residential main expansion of forty (40)

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years from the in-service date which EGD applies to determine the economic feasibility of system expansion, as described in Exhibit B2, Tab 1, Schedule 1, page 4 of 9.

Would you please bring the contents of this letter to the attention of your Cost of Capital Witness Panel so that they will be prepared to respond to this line of inquiry when we cross-examine them next week.

Yours very truly

Peter C.P. Thompson, Q.C.

PCT\slc
enclosures
c. Board Secretary
Intervenors EB-2006-0034

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National Energy Board
Office national de l'énergie

Reasons for Decision

TransCanada PipeLines Limited

RH-1-2002

July 2003

Tolls and Tariff

disagreement between TransCanada and GFI on net salvage on terminal retirements remains unresolved. In Ontario's view, there would be greater cost certainty if all elements of depreciation, including net salvage on terminal retirements, were dealt with at once in one proceeding. In addition, approving TransCanada's claim for depreciation will further reduce the cost competitiveness of the Mainline. For these reasons, Ontario submitted that TransCanada's claim related to depreciation should be denied.

Views of the Board

Other Matters

The Board notes the importance of performing depreciation studies on a timely basis and of ensuring that depreciation rates reflect up-to-date information. The Board notes TransCanada's expert witness recommended that depreciation studies be performed every three to five years and that TransCanada accepted this recommendation. Accordingly, the Board would expect the filing of TransCanada's next comprehensive depreciation study to be within this time frame.

The Board does not agree with Ontario's suggestion that the Board delay a decision on depreciation matters until all elements of depreciation, including net salvage on terminal retirements, could be dealt with in one proceeding. In the Board's view, denying all of TransCanada's depreciation proposals at this time would result in an improper recovery of depreciation expenses in 2003 and future shippers having to pay disproportionately large depreciation charges.

Overall Views on Depreciation

The Board is of the view that it would be appropriate to implement a composite depreciation rate that reflects all aspects of the TransCanada depreciation study, with the exception of the proposed change from ASL to ELG. Further, the Board is of the view that TransCanada should offset any salvage proceeds it may receive from the disposition of assets in accounts subject to amortization accounting against the additions in a particular vintage year and then apply amortization accounting to the net amount. Based on TransCanada's calculations, which are reproduced in Table 5-1, the Board expects that the resulting composite depreciation rate will be approximately 3.42% for 2003. The exact level of the composite depreciation rate will be confirmed once TransCanada files its compliance tolls filing.

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)		
1	Total provision for depreciation and amortization before adjustments (per page 3)	$	179,652
2	Adjustments: vehicle depreciation through clearing		1,150
3	Provision for depreciation amortization and depletion	$	178,502

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)	Provision (c)
	Intangible plant:			
1	Franchises and consents	$ 2,090		$ 69
2	Intangible plant - Other	9,370		123
3		$ 11,460		$ 192
	Local Storage Plant			
4	Structures and improvements	$ 2,193	3.30%	$ 72
5	Gas holders - storage	6,048	2.68%	162
6	Gas holders - equipment	6,895	3.68%	254
7		$ 15,136		$ 488
	Storage:			
8	Land rights	$ 51,512	2.23%	$ 1,149
9	Structures and improvements	55,744	2.34%	1,304
10	Wells and lines	140,026	2.66%	3,725
11	Compressor equipment	276,181	3.19%	8,810
12	Measuring & regulating equipment	56,053	4.3%	2,410
13	Other equipment	0	0.00%	0
14		$ 579,515		$ 17,398
	Transmission:			
15	Land rights	$ 37,019	2.00%	$ 740
16	Structures and improvements	44,286	2.66%	1,178
17	Mains	962,589	2.37%	22,813
18	Compressor equipment	172,791	3.52%	6,082
19	Measuring & regulating equipment	124,178	3.61%	4,483
20		$ 1,340,863		$ 35,296
	Distribution - Southern Operations:			
21	Land rights	$ 4,500	1.67%	$ 75
22	Structures and improvements	71,534	2.91%	2,082
23	Services - metallic	110,630	3.69%	4,082
24	Services - plastic	675,920	3.18%	21,494
25	Regulators	63,177	3.30%	2,085
26	Regulator and meter installations	52,975	3.51%	1,859
27	Mains - metallic	391,540	2.54%	9,945
28	Mains - plastic	450,811	2.34%	10,549
29	Measuring & regulating equipment	37,141	4.64%	1,723
30	Meters	171,304	3.70%	6,338
31	Other equipment	0	0.00%	0
32		$ 2,029,532		$ 60,232

UNION GAS LIMITED
Provision for Depreciation,
Amortization and Depletion
Calendar Year Ending December 31, 2007

Line No.	Particulars ($000's)	Average Plant (1) (a)	Rate (%) (b)	Provision (c)
	Distribution plant - Northern & Eastern Operations:			
1	Land rights	$ 8,821	1.68%	$ 148
2	Structures & improvements	46,134	3.13%	1,444
3	Services - metallic	87,724	3.58%	3,141
4	Services - plastic	317,464	3.19%	10,127
5	Regulators	23,146	3.34%	773
6	Regulator and meter installations	22,102	3.50%	774
7	Mains - metallic	316,087	2.52%	7,965
8	Mains - plastic	176,582	2.35%	4,150
9	Compressor equipment	1,341	3.34%	45
10	Measuring & regulating equipment	77,066	4.63%	3,568
11	Meters	52,881	3.67%	1,941
12	Other distribution equipment	0	0.00%	0
13		$ 1,129,346		$ 34,075
	General:			
14	Structures and improvements	$ 38,193	2.13%	$ 814
15	Office furniture and equipment	15,552	6.67%	1,037
16	Office equipment - computers	84,040	25.00%	21,010
17	Transportation equipment	49,489	10.07%	4,984
18	Transportation equipment - aircraft	0	3.40%	0
19	Heavy work equipment	13,912	4.55%	633
20	Tools and other equipment	31,252	6.67%	2,083
21	Communications equipment	18,688	6.67%	1,246
22	Communications structures	3,361	4.88%	164
23	Other equipment	0	0.00%	0
24		$ 254,486		$ 31,971
27	Contributions in aid of construction	0	2.50%	0
28	Sub-total	$ 5,360,339		$ 179,652
25	Total provision for depreciation and amortization			$ 179,652
26	Depreciation through clearing			1,150
27		$ 5,360,339		$ 178,502

Notes:

(1) A simple average of the opening and closing plant balances was used to calculate the annual depreciation provision.

Castanza, Suzanne

From: Thompson, Peter C. P.

Sent: February 2, 2007 12:43 PM

To: 'Cass, Fred'

Cc: Board Secretary; DeRose, Vincent J.; Abouchar, Juli; Adams, Tom; Aiken, Randy; Alexander, Basil; Battista, Richard; Buonaguro, Michael; Cass, Fred; Chiasson, Lorraine; Clark, Janet; Crain, Kirsten; Cramer, Duane; DeMarco, Elisabeth; DeRose, Vincent J.; DeVellis, John; Duffy, Patrick; Duzy, Margaret; Findlay, Rob; Fournier, Peter; Gibbons, Jack; Gibbs, Andrea; Girvan, Julie; Harbell, James; Higgin, Roger; Hoaken, Eric; Hoey, Patrick; Jackson, Malcolm; Kerr, Paul; Klewchuk, Patricia; Klippenstein, Murray; Ladha, Shiraz; Landymore, Heather; Luymes, Martin; MacDonald, Glen; MacIntosh, David; Manning, Paul; Matthews, Dave; Matz, Thomas; Mauviel, Lise; McCamus, Greg; McMahon, Pat; Millar, Michael; Millyard, Kai; Newton, Murray; Nolan, Catherine David; O'Connor, Sandy; Pelletier, Bernard; Persad, Tania; Poch, David; Reuber, Barbara; Ross, Murray; Ruzycki, Nola; Scott, Jennifer; Serafini, Pete; Shepherd, Jay; Spratt, Shari-Lynn; Stacey, Jason; Thompson, Peter C. P.; Toronto Hydro; transcanada_mainline@transcanada.com; Warren, Robert; Watson, Tanya; Wightman, James; Williams, Bob; Young, Valerie; Clermont, Marc; Killeen, Bill; Makohoniuk, Rodney

Subject: EB-2006-0034 - IGUA Letter

Attachments: LTR Cass Feb 02 2007.pdf; OTT01-3137919-v1-LTR_Cass__Attachments.PDF

Attached please find a letter and enclosure submitted by the Industrial Gas Users Association ("IGUA").

Peter C.P. Thompson, Q.C.
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Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0001/EB-2005-0437

IN THE MATTER OF AN APPLICATION BY

ENBRIDGE GAS DISTRIBUTION INC.

2006 RATES

DECISION WITH REASONS

February 9, 2006

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.3
DATE February 6, 2007
page 91 only.
08/99

10.10 SHOULD THE BOARD BE CONCERNED THAT ACTUAL PAYMENTS TO EI WILL BE IN ACCORDANCE WITH CAM – NOT RCAM?

10.10.1 It was clear from the evidence that regardless of the results of the RCAM, the payment for corporate services from Enbridge to EI will continue to be governed by CAM. Schools expressed concern regarding the payment of the CAM amount, and recommended the use of an Excess Earnings Variance Account to capture payments from overearnings.

10.10.2 Enbridge responded that it intended to honour its contracts, that it had a legal contract and that it needed the services governed by the contract. Enbridge submitted that the development of RCAM did not invalidate CAM. It asserted that RCAM was developed in recognition of the need to tailor the methodology to meet the needs of the Board. Enbridge maintained that it was practical to use CAM because of other subsidiaries within the EI Group.

10.11 BOARD FINDINGS

10.11.1 The Board is concerned that CAM will govern actual payments. The Board notes the testimony of both Enbridge and EI witnesses to the effect that the RCAM is more rigorous than CAM. As a result, the Board believes that the continued operation of CAM suggests that Enbridge and EI's commitment to the RCAM methodology will be tempered. There is also the potential for an adverse financial impact on Enbridge if it finds it must make budget reductions elsewhere to make "scorecard" targets and payments to EI in accordance with CAM. The Board will not establish the variance account proposed by Schools, but this is an area that is of interest to the Board and one which the Board will monitor going forward.

7.4

Enbridge Gas Distribution
2006 Actual EBIT Coverage of Interest

	OEB Normalized Allowed	Impact of Actual Weather	Weather Adjusted	Impact of Other Utility Actual Variances	Total Ontario Utility Results	[redacted]	St. Lawrence Gas Impact	Impact of Corporate Costs Not Recovered In Rates	Impact of Intercompany Financing & Other Corporate Items	Total EGD Legal Entity
Earnings Before Interest Expense and Income Taxes (EBIT) ($ millions)	346.87	(57.70)	289.17	7.81	296.98		2.73	(27.40)	100.59	372.90
Interest Expense ($ millions)	165.05	0.00	165.05	(3.66)	161.39		1.24	0.00	40.23	202.86
EBIT Interest Coverage (times)	2.10		1.75		1.84		2.20		2.50	1.84

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.4
DATE February 6, 2007
08/99

EBRO 479 K7.5

Ontario Energy Board
FILE No. EB-2006-0034
EXHIBIT No. K7.5
DATE February 6, 2007
decision - EBRO 479
08/99

7. COST OF CAPITAL

7.0.1 The Board has determined that, for the purposes of this Decision, the following issues need to be addressed:

- Financial Flexibility and Risk
- Capital Structure
- Cost of Long-Term Debt
- Return on Common Equity

7.0.2 As stated in Chapter 3 of this Decision with Reasons, the Board, for the purposes of determining the Company's cost of capital in the test year, has accepted 5.95 percent as the indicated cost of short-term debt.

7.0.3 The Board's findings on cost of capital, as set out in this chapter, are summarized in Appendix C.

7.1 FINANCIAL FLEXIBILITY AND RISK

7.1.1 Dr. Sherwin/Ms McShane contended that the financial risk of the Company has continued to rise. The narrowing of the spread between the allowed utility return on equity and the embedded cost of debt, and the earnings shortfall have in their opinion contributed to a decline in utility interest coverage and limited the Company's financial flexibility. This view was also supported by another Company consultant, Mr. Lackenbauer, who testified that the existing common equity ratios and high level of debt are "endangering" the credit ratings and financial flexibility of the Company. Consumers Gas noted that credit rating agencies have set 2.5 times interest coverage as a general benchmark in assessing a class "A" rating, and that Canadian Bond Rating Services Inc. had indicated that interest coverage ratios would need to improve for the Company to maintain current debt ratios.

7.1.2 Consumers Gas maintained that its financial flexibility has been affected by the shortfall in earnings experienced in fiscal 1991 and 1992 and the decline in interest coverage ratios. The Company stated that it was unable to access the long-term debt market between April 1991 and April 1992. It requested that the Board give it flexibility in its equity ratios and an adequate equity return.

7.1.3 Dr. Sherwin/Ms McShane maintained that there was no material change in business risk since E.B.R.O. 473.

Positions of the Parties

7.1.4 Board Staff submitted that the Company's financial risk has not changed substantially from fiscal 1992 to justify either an increase in the return on equity or the equity ratio for fiscal 1993. Dr. Winter testified that the issue test provisions would not significantly constrain the Company's access to debt markets. He indicated that, for fiscal 1994, at a 35 percent equity ratio, $100 million in debt could be raised in the first month under the issue test, assuming an interest rate of nine to ten percent and an achieved return on equity of ten percent. Board Staff argued that even a 12 percent allowed return would result in a times interest earned ratio of 2.11, which would be higher than under the rates of return approved by the Board for fiscal 1991 (2.02), though not quite as high as fiscal 1992 (2.15). It submitted that the risk of a reduced credit rating in 1993, barring other factors such as weather and a severely depressed economy, is highly unlikely.

7.1.5 IGUA contended that the submissions of the Company relating to a decline in credit rating are "scare tactics", and submissions based on such "fear-mongering" evidence should be rejected as being unreasonable and without merit.

7.1.6 Both IGUA and CFBA/OCAP agreed that there was no material change in business risk since E.B.R.O. 473. However, Dr. Winter concluded that business risk has declined.

Board Findings

7.1.7 The Board has taken into account all the evidence, testimony and arguments of the parties with respect to the impacts of its decisions and the Company's need for financial flexibility. The Board, again, appreciates the assistance which the parties have provided through their efforts to instill objectivity into what is a highly subjective area of analysis and forecasting.

7.1.8 The Board finds that the overall financial and business risk exposure for fiscal 1993 is similar to that which existed in fiscal 1992.

7.2 CAPITAL STRUCTURE

7.2.1 Consumers Gas was reorganized to effect the transfer of the business activities and assets that were not part of its Ontario gas distribution and storage business to British Gas Holdings at fair market value. This reorganization was completed by February 1992, with an effective date of January 31, 1992.

7.2.2 In E.B.R.O. 473 the Board found the common equity component for the Company to be a deemed 35 percent for the 1992 test year. Due to the reorganization, Consumers Gas requested an actual projected common equity ratio for the 1993 test year and thereafter. It maintained that using an actual common equity and not a deemed common equity ratio gives the Company the flexibility to adjust for changes in risk. Consumers Gas set an internal target for the common equity ratio over the next five years in the range of 35 to 37 percent to reflect the non-linear impact on the common equity ratio of periodic common equity issues. It specifically proposed a capital structure that contains a projected actual ratio of 35.51 percent.

Positions of the Parties

7.2.3 Dr. Winter agreed with the Company's original proposal for a projected actual equity ratio of 35.5 percent. Board Staff submitted that the Board should approve a projected actual equity ratio for the test year but that it should be no higher than the current deemed equity ratio of 35 percent. Board Staff maintained that the deemed equity ratio of 35 percent remains appropriate as the risk of the utility has not changed substantially over the past year. Dr. Winter had suggested that a range of 34 to 36 percent would permit adequate access to debt markets, and that the Company's proposed upper limit of 37 percent was excessive. Board Staff submitted that the Board should not comment on the five year target ratio and expressed some concern that approval of a range would lend itself to an increase in the equity component of the capital structure. Further, Board Staff argued that, with a proposed rate base of $2 billion, a two percent range is unnecessary for purposes of financial flexibility and that there were no financial needs to justify a change to the debt-equity ratio.

7.2.4 IGUA did not support the change from a single point deemed common equity ratio to a projected actual equity ratio. It also submitted that the Board should not approve the target range concept as this will permit the

Company to "thicken" its equity and that there was no evidence to suggest that the current ratio of 35 percent was not reasonable. IGUA argued that the Board should continue to use a deemed common equity ratio of 35 percent. CFBA/OCAP recommended that the current capital structure be maintained and that the Company look to other financial instruments for financial flexibility if it finds itself unable to access the corporate bond market.

Board Findings

7.2.5 The Board notes that the immediate impact of the Company's proposal to employ an actual equity ratio would be an increase in the equity component. The Board finds that such a thickening is not justified by the evidence. The Board, therefore, rejects the proposed use of the Company's 35.51 percent actual equity as the equity component for ratemaking purposes in the fiscal year.

7.2.6 The Board deems a common equity ratio of 35 percent to be appropriate for Consumers Gas in fiscal 1993.

7.3 COST OF LONG-TERM DEBT

7.3.1 Consumers Gas requested that the Board accept 10.53 percent as the embedded cost of long-term debt for fiscal 1993. Although no incremental long-term debt issues were planned, the Company projected the replacement of previously issued debt with a $65 million debenture issue to be issued in March, 1993. The Company's forecast coupon rate on this issue is 9.10 percent, reflecting a spread of 85 basis points over its forecast of ten year Government of Canada bonds at 8.25 percent. After including issue costs, the effective cost rate of 9.24 percent has been included in the embedded cost of long-term debt calculation.

Positions of the Parties

7.3.2 Board Staff submitted that the coupon rate of the Company's debt issue would be 8.15 percent, not 9.10 per cent, based on Dr. de Bever's forecast of ten year Government of Canada bond yields (7.30 percent) and the 85 basis points spread. However, it estimated that the amount of the issue, compared to the total long-term debt of $1.1 billion, would have a minimal impact on the cost of capital. Therefore, Board Staff proposed that the cost of long-term debt submitted by the Company should be accepted by the Board.

7.3.3 IGUA supported the use of Dr. de Bever's estimates for Government of Canada bonds, and submitted that the $65 million debenture should use his ten year and over bond rate of 8.08 percent for fiscal 1993, plus a corporate premium of 85 basis points for a projected coupon rate rounded to nine percent.

Board Findings

7.3.4 The Board observes that the differences in the views expressed by the parties lead to results which would have only a minimal effect in the test year. The Board accepts the Company's assessment of the embedded cost of its proposed 1993 debenture issue at 9.24 percent and its forecast embedded cost of its total long-term debt at 10.53 percent for the test year.

7.4 RETURN ON COMMON EQUITY METHODOLOGIES

<u>Long-term Canada Bond Rates</u>

7.4.1 The Company's witnesses forecast a long-term Canada bond (30 year) rate of 8.75 percent for fiscal 1993 and Dr. de Bever forecast 8.2 percent.

7.4.1 The Company's witnesses forecast a long-term Canada bond (30 year) rate

7.4.2 Board Staff argued that 8.2 percent is reasonable given the continued poor prospect for economic recovery. IGUA preferred Dr. de Bever's rate over the higher rate of the Company's witnesses. It maintained that his long-term rate is consistent with the Bank of Canada policy to hold inflation near zero, and supported by the bridge year rates currently being experienced.

Comparable Earnings Test

7.4.3 This test estimates a return on equity for Consumers Gas by comparing the returns earned by a sample of low-risk industrials, adjusted to incorporate the specific risks of the utility over an appropriate time period.

7.4.4 The Company's witnesses applied the comparable earnings test to a sample of 28 companies for the period 1983 to 1991 to yield a 13.5 percent return. The result was then reduced by 30 basis points for the lower risk of the utility for a return on equity of 13.2 percent. They did not regard an adjustment for market-to-book ratios to be appropriate.

7.4.5 Dr. Winter selected 20 companies and used two business cycles, the historical business cycle, 1983 to 1991 and the current/prospective business cycle, 1985 to 1993, to produce returns of 12.45 percent and 11.62 percent respectively. He then reduced the results by 50 basis points for risk and 25 basis points for the market-to-book ratio to arrive at returns of 11.70 and 10.87. The adjustment for the market-to-book ratio is to compensate for non-balance sheet assets and inflationary distortions on book valued assets and to bring the Company's book rate of return closer to its opportunity cost of capital. The average of the results, 11.25 percent, was Dr. Winter's estimate for a fair rate of return under the comparable earnings test.

7.4.6 Board Staff, contending that information about current and proposed rates of return better reflects the rates of return available in the current business cycle, supported the inclusion of the 1993 returns. The Company argued that if weight is to be given to Dr. Winter's evidence, then 1992 and 1993 should be disregarded and only the "raw return" for the business cycle 1983 to 1991 (12.45 percent) should be considered. In other words, the Board should ignore the downward adjustment as the resulting return is below the cost of attracting capital.

7.4.7 IGUA submitted that the only thing the evidence showed was that the results of the test can differ. Therefore, it argued that the results of both the Company's and Board Staff's consultants should be considered. IGUA noted the midpoint of the two results is 12.2 percent. CFBA/OCAP maintained that the comparable earnings test should be adjusted by 100 basis points to better reflect the lower risk of the Company. Further, it argued that the market-to-book ratio adjustment should be even greater than Dr. Winter's 25 basis points. CFBA/OCAP suggested that a return of 11.4 percent would be a fair, generous and conservative rate of return for the Company under the test.

Equity Risk Techniques

7.4.8 This methodology compares the returns on equity investments to those of low risk long-term Canada bonds to derive the shareholder risk premium associated with equity investments. The forecast rate for long Canada bonds is added to the premium and the result is adjusted. Some of the parties noted that the cost of attracting capital has traditionally been adjusted by the Board at a market-to-book ratio of 115 percent for flotation cost, market pressure, and financial flexibility.

7.4.9 The Company's witnesses used a long Canada yield of 8.75 percent and relied on a risk premium of 3.5 to 3.75 percent for a cost of 12.375 percent. This was then adjusted for financial flexibility for a cost of 13.5 percent. Using Dr. de Bever's forecast of 8.2 percent, Board Staff noted that the Company's cost under this test would be reduced by 55 basis points to 12.95 percent.

7.4.10 Dr. Winter used Dr. de Bever's long Canada rate of 8.2 percent and a lower risk premium (1.91 to 2.5 percent) for a cost of equity, adjusted, in the range of 11.0 to 11.7 percent. He derived the lower specific risk premium by using a beta risk test. Board Staff submitted that Dr. Winter's range would provide a 2.9 to 3.5 percent return over the long Canada bond forecast. Board Staff argued that this is in line with Mr. Lackenbauer's testimony in support of a risk premium of three percent over government bonds. The Company submitted that Dr. Winter's reliance on beta in his calculation should not be accepted as it is an unreliable method for establishing a reasonable risk premium for the Company. Moreover, the Company argued that a risk premium of 1.9 to 2.5 percent will not meet investor requirements in that an investor would need a return of at least three percent over a long bond yield of 8.75 percent. When adjusted at 115 percent, this results in a minimum cost of equity of 12.8 percent.

7.4.11 IGUA, using Dr. de Bever's forecast for long Canadas and a market risk premium of 3.375 percent, submitted that the cost of equity would be 11.6 percent, when rounded. It calculated a market risk premium using the Board's previous findings on common equity (13.125 percent) and the cost of long-term debt (9.75 percent) in E.B.R.O. 473.

7.4.12 CFBA/OCAP maintained that the estimates of the equity market risk premium over long Canadas by all the witnesses were excessive. It recommended a lower market risk premium for an overall return of 11.95 to 12.15 percent. CFBA/OCAP also objected to the market-to-book value adjustment, and submitted that there was no evidence that supported the underestimation of the fair rate of return. It asked that the Board reconsider the use of the adjustment factor.

7.5 **RETURN ON COMMON EQUITY**

Positions of the Parties

7.5.1 The Company's witnesses gave equal weight to the comparable earnings and risk premium tests. It was their conclusion that the fair return on equity for the Company is 13.375 percent on an actual capital structure of 35.51 percent common equity. If the return were to be lower, they maintained that the common equity component would have to be higher.

7.5.2 Dr. Winter attached a 25 percent weighting to the comparable earnings test result of 11.24 percent and 75 percent to the equity risk premium point of 11.0 percent for a point estimate of 11.1 percent as the lower limit. He made no adjustment to the upper limit of the equity risk premium point of 11.7 percent. Board Staff submitted that, given Dr. Winter's recommendations, the decline in interest rates, the trend in the capital market and the rates of return available to potential investors since 1992, and the approved return in fiscal 1992, a return on common equity of 13.125 percent would be excessive for fiscal 1993. It maintained that the appropriate return is in the range of 11.7 percent to 12.5 percent. Board Staff recommended a rate of return of 12.5 percent on a 35 percent actual common equity ratio for fiscal 1993.

7.5.3 IGUA submitted that the Board should look at the 13.125 percent awarded in E.B.R.O. 473, and take into account the changes that have occurred in risks and economic conditions and the trends in equity awards granted by other regulators. Recent decisions in other jurisdictions have seen a reduction of about 125 basis points. IGUA pointed out that Consumers Gas' recommendation is only 67.5 basis points below the Company's recommendation in E.B.R.O. 473. IGUA, prescribing a 50/50 weighting to the results of the two tests (12.2 percent and 11.6 percent), submitted that the Board should find a rate of return of no more than 11.9 percent on a 35 percent deemed common equity ratio for fiscal 1993.

7.5.4 CFBA/OCAP submitted that changes in the money market, evidenced by the decrease in the yields of long-term Canada bonds, necessitate a lower rate of return. It recommended that the Board accept the lower range of Dr. Winter's recommendation and allow a return on equity of 11.0 percent.

7.5.5 The following table displays the submissions on the equity return requirement:

	Sherwin/McShane (Company)[1]	Winter	Board Staff	IGUA	CFBA
Comparable Earnings Test	13.2%	11.25%	-	12.2%	11.4%
Equity Risk Techniques	13.5%	11.0 - 11.17%	-	11.6%	11.95 - 12.15%
Return Recommendation	13.375%	11.1 - 11.7%	12.5%	11.9%	11%

[1] based on an equity component of 35.51%, all others were at 35%

Board Finding

7.5.6 After considering all the evidence and arguments in this proceeding, the Board finds that the Company's authorized fair rate of return for the test year on a deemed common equity component of 35 percent shall be 12.3 percent.

THE CONSUMERS' GAS COMPANY LTD.
CAPITALIZATION AND COST OF CAPITAL
For The Year Ending September 30, 1993
($ million)

PER COMPANY (1)

	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	1,145.6	55.11%	10.53%	5.80%	120.6
Short-Term Debt	89.1	4.29%	7.92%	0.34%	7.1
Preference Capital	105.9	5.09%	8.80%	0.45%	9.3
Common Equity	738.1	35.51%	13.375%	4.75%	98.7
Total	2,078.7	100.00%		11.34%	235.7

(1) Includes Evidence Updates and Impact Statement Adjustments, but Excludes ADR.

PER BOARD

	Capital Structure	Ratios	Cost Rate	Return Component	Return
Long-Term Debt	1,145.6	55.36%	10.53%	5.83%	120.6
Short-Term Debt	93.7	4.53%	5.95%	0.27%	5.6
Preference Capital	105.9	5.12%	8.80%	0.45%	9.3
Common Equity	724.3	35.00%	12.30%	4.31%	89.1
Total	2,069.5	100.01%		10.86%	224.6

UNDERTAKING J2.1

UNDERTAKING

Tr: 53

Advise what steps, if any, have been taken by EGD to educate customers in Rates 100 or higher about the company's risk management program and the necessity, if any, for those customers to undertake their own risk management.

RESPONSE

The Company conducted a series of information meetings in June 2005 that all customers in Rates 100 and higher were invited to attend. One of the topics covered in these meetings was an overview of the natural gas industry. This was intended as an education session for these customers. A component of this overview was a general discussion on risk management and what different hedges can do for managing price volatility. The presentation also touched briefly on Enbridge Gas Distribution's risk management activities, highlighting the objective of the program being to reduce volatility, not cost. The presentation did not however make specific reference to the necessity, if any, for system gas customers to undertake their own risk management.

Witnesses: D. Charleson
K. Irani

UNDERTAKING J2.2

UNDERTAKING

Tr: 55

Advise whether EGDI obtains financial instruments or mechanisms for risk management program from any affiliates or related companies.

RESPONSE

Enbridge Gas Distribution has not obtained any hedge instruments in support of its risk management activities from any affiliate or related company.

Witnesses: D. Charleson
K. Irani

UNDERTAKING J6.1

UNDERTAKING

Update Table 4 of Exhibit E2, Tab 1, Schedule 1 for the actual normalized utility return on equity.

RESPONSE

Col. 1	Col. 2	Col. 3	Col. 4
	Test Year	Normalized Actual ROE Utility EBIT Interest Coverage (times interest coverage)	EBIT Margin Above 2 Times Coverage ($ Millions)
1.	1993	2.60	75.3
2.	1994	2.43	56.0
3.	1995	2.45	62.6
4.	1996	2.50	76.5
5.	1997	2.53	84.3
6.	1998	2.49	80.5
7.	1999	2.38	64.7
8.	2000	2.36	52.6
9.	2001	2.26	41.3
10.	2002	2.50	70.8
11.	2003	2.19	28.4
12.	2004	NA	NA
13.	2005	2.18	27.6

Witness: B. Boyle