BOARD STAFF INTERROGATORY #1

INTERROGATORY

ISSUE 1 – CALCULATIONS IN ACCORDANCE WITH SETTLEMENT AGREEMENT

Ref: Ex. B /Tab 1/ Sch 2 /

Please confirm that there have been no departures from the terms of the EB-2007-0615 settlement for the calculation of the 2010 revenue requirement, assignment of the revenue requirement to the rate classes, and the derivation of the 2010 rates. If there were departures, please identify the nature of those departures.

RESPONSE

Confirmed.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

ISSUE 5 – GAS VOLUME BUDGET

Ref: Ex. B /Tab 1/ Sch 5/

a. Please provide a table of historic and forecast gas volumes, in a similar format to the example shown below, broken down by general service and contract that shows the Board-approved versus the actual volumes for the 5-year period 2005 through 2009. Please also include the 2010 forecast. Additionally, please include the average number of customers.

Example

	Year 1		Year 2		Year 3	
	Board-approved	Actual	Board-approved	Actual	Board-approved	Actual
General Service						
Contract						
Total Volume						
No. Customers (avg.)						

b. Please also provide a table similar to part a. above showing weather-normalized volumes.

RESPONSE

a. Table 1 provides the requested information. In order to facilitate the Board's review, meter reading or billing conventional heating degree days are also provided herein.

b. Table 2 illustrates the requested information. In order to compare the year over year variance between actual and Board Approved normalized numbers on the

Witnesses: I. Chan
T. Ladanyi

same basis, each year's actual results have been normalized to the corresponding Board Approved degree days for that year.

During the requested time period, the Company and ratepayers have experienced many economic events that have had an impact on annual use or worse, causing plant shut downs.

Some of these events would include:

- Unexpected and historically high natural gas prices that occurred in 2005 and 2006;
- unforeseen rate switching commencing Fall 2006 as discussed in details at EB-2008-0219, pages 28-30 of Exhibit B, Tab 1, Schedule 5;
- rapidly deteriorating economic conditions that took root in the early fall of 2008; and
- the migration between Rate 115 to Rate 125 (which has no distribution volume).

In spite of these factors, the average total normalized percentage error variances (i.e., Actual vs Board Approved Budget) during 2003-2004 and 2007 was a very low 0.4% or 45 10^6m^3.

As stated in paragraphs 54 to 57 of Exhibit B, Tab 1, Schedule 5 and in EB-2009-0055, Exhibit B, Tab 3, Schedule 2, on page 3 and at Exhibit C, Tab 1, Schedule 5, the reduction in volumes between 2009 weather normalized actual of 11 025.1 10^6m^3 and 2009 Board Approved Budget of 11 399.8 10^6m^3 is consistent with 2009 Bridge Year Estimate volumes of 11 057.0 10^6m^3. This reduction is not unexpected in the wake of the rapidly deteriorating economic conditions that began in October 2008. The reduction is mainly comprised of unfavourable general service customer growth and average use as well as contract market customers' plant closures and production shutdown.

Since the 2009 Board Approved Budget was developed during the early summer of 2008, prior to the onset of the economic downturn, the Budget did not reflect the significant increase in plant closures and business bankruptcies, a 26-year low in Canadian consumer confidence, and an unemployment rate that reached a 15-year high of 9.4 per cent in the Spring as mentioned in paragraph 57 of Exhibit B, Tab 1, Schedule 5.

For example, in the spring of 2008 it could not have been realistically predicted that two large automakers would require bankruptcy protection during 2009.

Table 1 - Weather Un-Normalized Volumes, Customers and Degree Days

(Volumes in $10^6 m^3$)

	2003		2004*		2005		2006		2007		2008		2009		2010
	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Board-Approved	Actual	Budget
General Service	7,374.5	8,228.9	7,511.8	7,916.3	7,963.9	7,950.4	7,932.8	7,490.5	7,642.2	8,314.8	8,288.0	8,806.0	9,083.2	9,129.2	9,083.5
Contract	4,400.2	4,417.3	4,309.7	4,340.5	4,334.2	4,215.6	4,387.9	3,996.4	4,134.3	3,758.5	3,355.2	3,101.5	2,316.6	2,205.6	2,008.6
Total Volumes	11,774.7	12,646.2	11,821.5	12,256.8	12,298.1	12,166.0	12,320.7	11,486.9	11,776.5	12,073.3	11,643.2	11,907.5	11,399.8	11,334.8	11,092.1
No. Customers (avg.)	1,615,037	1,622,016	1,672,586	1,676,380	1,718,766	1,724,716	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528
Meter Reading Degree Days (18°C)	3,565	4,029	3,565	3,774	3,752	3,728	3,745	3,448	3,617	3,613	3,543	3,750	3,514	3,764	3,546

Note:
As both of historical Board Approved degree days, customers and volumes were developed based upon fiscal year information up to 2005, they are presented on a fiscal-year basis up to 2005 in this table. From 2006 onwards, they are presented on a calendar-year basis.

* 2004 Bridge Year Estimate from RP-2003-0203 was reported here as Board Approved numbers are not available since there was no 2004 Board Approved Volume Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

** In consequence of the ADR settlement agreement in capital expenditure, there was a reduction in customers of 1,022 to the board approved budget numbers.

Table 2 - Weather Normalized Volumes and Customers

(Volumes in $10^6 m^3$)

	2003		2004*		2005**		2006		2007		2008		2009		2010
	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Board-Approved	Normalized Actual	Budget
General Service	7,374.5	7,345.5	7,511.8	7,458.4	7,963.9	7,822.8	7,932.8	7,901.9	7,642.2	8,037.9	8,288.0	8,369.7	9,083.2	8,833.7	9,083.5
Contract	4,400.2	4,380.7	4,309.7	4,275.9	4,334.2	4,199.2	4,387.9	4,119.1	4,134.3	3,739.8	3,355.2	3,099.6	2,316.6	2,191.4	2,008.6
Total Volumes	11,774.7	11,726.2	11,821.5	11,734.2	12,298.1	12,022.0	12,320.7	12,021.0	11,776.5	11,777.7	11,643.2	11,469.3	11,399.8	11,025.1	11,092.1
No. Customers (avg.)	1,615,037	1,622,016	1,672,586	1,676,380	1,718,766	1,724,716	1,792,615	1,782,813	1,823,258	1,824,789	1,864,047	1,865,020	1,906,437	1,887,605	1,931,528
Meter Reading Degree Days (18°C)	3,565	3,565	3,565	3,565	3,752	3,752	3,745	3,745	3,617	3,617	3,543	3,543	3,514	3,514	3,546

Note:
As both of historical Board Approved degree days, customers and volumes were developed based upon fiscal year information up to 2005, they are presented on a fiscal-year basis up to 2005 in this table. From 2006 onwards, they are presented on a calendar-year basis.

* 2004 Bridge Year Estimate from RP-2003-0203 was reported here as Board Approved numbers are not available since there was no 2004 Board Approved Volume Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

** In consequence of the ADR settlement agreement in capital expenditure, there was a reduction in customers of 1,022 to the board approved budget numbers.

Witnesses: I. Chan
T. Ladanyi

BOARD STAFF INTERROGATORY #3

INTERROGATORY

ISSUE 5 – GAS VOLUME BUDGET

Ref: Ex. B /Tab 1/ Sch 4 /

Please provide a Bill Impact sensitivity analysis for 2010 for typical Rate 1 and Rate 6 customers relative to different budgeted gas volumes. What is the effect of a plus 400 10^6m^3 and a minus 400 10^6m^3 change to the total Gas Volume Budget? Assume the same proportion of volumes to General Service and Contract Customers as provided in the filed 2010 gas volume budget

RESPONSE

Table 1 below presents the requested impact on Rate 1 and 6 customers from increasing the total gas volumes budget by 400 10^6m^3 and decreasing the total gas volume budget by 400 10^6m^3. The rate class breakdown of 400 10^6m^3 is assumed to be consistent with the current profile of the 2010 total gas volume budget.

Due to time limitations, it has been assumed that the addition or reduction of 400 10^6m^3 is added to/removed from the system without the addition of new customers or a loss of existing customers. If the Company were to increase or decrease its total volumes budget by 400 10^6m^3, and assume customer numbers would change, the distribution revenue requirement would need to change to capture this impact. The gas cost to operations budget would also need to be updated to capture the gas cost consequences of these volume changes. Given these assumptions, the approximate average rate impacts for Rate 1 and 6 classes assuming no change in the proposed total revenue requirement are as follows:

Witnesses: J. Collier
A. Kacicnik

Table 1: 2010 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact Based on 400 $10^6 m^3$ Increase
1	0.3%
6	0.1%

Rate Class	T-Service Rate Impact Based on 400 $10^6 m^3$ Decrease
1	3.2%
6	2.6%

Witnesses: J. Collier
A. Kacicnik

BOARD STAFF INTERROGATORY #4

INTERROGATORY

ISSUE 6 – Y FACTOR – POWER GENERATION

Ref: Ex. B /Tab 2/ Sch 1/

With respect to the Y Factor request of $3.7 million for 2010, please provide the rate base amounts related to the Portlands Energy Centre and Thorold Cogen.

RESPONSE

The forecast 2010 rate base amounts related to Portlands Energy Center and Thorold Cogen, which support the requested $3.6 million deficiency (Updated: 2010-01-22), are as follows (stated on an average of monthly averages basis):

Portlands Energy Centre: ($000's)

Gross	23,269.0
Accumulated Depreciation	(1,752.7)
PP&E (net)	21,516.3

Thorold Cogen: ($000's)

Gross	6,586.1
Accumulated Depreciation	(190.8)
PP&E (net)	6,395.3

Witnesses: K. Culbert
T. Ladanyi

BOARD STAFF INTERROGATORY #5

INTERROGATORY

ISSUE 7 – Y FACTOR – DSM PROGRAM

Ref: Ex. B /Tab 2/ Sch 2/

The Board's Decision and Order in EB-2009-0154 (page 7) specifies that the funding for Enbridge's proposed Industrial Support Pilot Program ($1.25 million) must come from outside of the company's DSM budget. Please clarify whether the amount is in or out of the 2010 DSM budget.

RESPONSE

The $1.25 million incremental funding for the Industrial Support Pilot Program was approved by the Board for inclusion in Rates. This funding is incremental to the base 2010 DSM Budget as defined by the formula approved in EB-2006-0021 and as such is not considered to be funded from the 2010 DSM budget.

Please refer to the Company's evidence filed at Exhibit B, Tab 2, Schedule 2, page 4 updated 2010-01-22.

Witnesses: A. Mandyam
P. Squires

BOARD STAFF INTERROGATORY #6

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

Ref: Ex. B /Tab 3/ Sch 1/

Paragraph 3 says that the Company's pension surplus has, over a number of years, resulted in a significant ratepayer benefit. Please quantify the actual credit to the Revenue Requirement in the most recent 4 years that the plan has been in a surplus position, prior to the introduction of the IR Plan.

RESPONSE

The benefit arises in the form of cost avoidance, rather than by way of a direct credit to revenue requirement. Absent the surplus that was maintained by the plan, the minimum contribution requirement would have been the annual service cost, which would have averaged approximately $13 million for the years 2004 to 2008.

The annual service cost in each of 4 years preceding onset of the IR plan are noted below:

Year	Annual Service Cost ($ million)
2007	15.6
2006	13.2
2005	10.8
2004	9.7

Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #7

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

Ref: Ex. B /Tab 3/ Sch 1/

Paragraph 5 states that EGD is required to file its next pension valuation as at December 31, 2009 in order to remain compliant with the PBAO. When is the earliest date that this valuation would be available for filing in this proceeding?

RESPONSE

As noted in the evidence, this would be available no earlier than April 2010.

Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #8

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

Ref: Ex. B /Tab 3/ Sch 1/

Paragraph 12 states that Mercer estimated that based on the December 31, 2008 valuation, and the requirement to pay a Pension Benefits Guarantee Fund premium, the total annual contribution would be $18.9 million. What are the key assumptions that underpin the calculations of the funding requirement estimated by Mercer?

RESPONSE

The estimated requirement to contribute $18.9 million is based on the following components:

- DB current service cost,
- Special payments,
- DC current service cost, and
- PBGF premium

The key assumptions underpinning the derivation of the various components are noted in section 4 and Appendix B of the 2008 valuation report, attached in response to APPRO Interrogatory #1 at Exhibit I, Tab 2, Schedule 1.

Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #9

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

Ref: Ex. B /Tab 3/ Sch 1/

Paragraph 21 indicates that the financial "meltdown" could not have been foreseen by EGD's management. Does Enbridge Gas Distribution Inc. directly manage the plan or is it managed by another entity? Please name the corporate entity managing the plan. Does the plan include only the employees and retirees of Enbridge Gas Distribution Inc. or are there employees (such as those of affiliated companies) included in the plan? If so, please provide details as to the numbers of employees and the identity of the affiliates.

RESPONSE

The Board of Directors of Enbridge Gas Distribution Inc. delegated the overall responsibility for administration and investment of the Pension Plan to the Human Resources & Compensation Committee ("HRCC") of the Enbridge Inc. Board of Directors on May 1, 2002. The Board of Directors delegated this responsibility after satisfying themselves that the members of the HRCC and its agents and employees had the necessary skills, training, and expertise to oversee and administer the Pension Plan.

Enbridge employs a strong pension governance process that is reviewed regularly by EGD and EI internal staff as well as external consultants and updated where process improvements are identified. Part of this process is the use of external asset investment managers that are carefully chosen, given specific investment mandates, monitored on a regular basis by Enbridge Inc. staff and replaced if deemed appropriate.

While the Enbridge Gas Distribution Inc. Pension Plan has participating employers, the future contribution requirements noted in the evidence entirely relate to the employees and retirees of Enbridge Gas Distribution Inc.

There are currently five employers participating in the EGD registered plan, with EGD making up the majority of plan membership. A breakdown of plan membership by participating employer, as at December 31, 2008, is given below.

Witnesses: J. Haberbusch
N. Kishinchandani

Participating Employer	Plan Members
Enbridge Gas Distribution Inc.	3,361
Enbridge Solutions Inc.	21
Enbridge Electric Connections Inc.	31
Enbridge Gas New Brunswick Inc.	143
Gazifere Inc.	88
Total	3,644

Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #10

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

Ref: Ex. B /Tab 3/ Sch 1/

Paragraph 23 indicates that "the Enbridge pension governance structure in place ensured a prudent response to events as they unfolded". Please identify the responsive steps that the plan manager undertook during the financial crisis of 2008 and 2009. How were those actions different from the actions of other Canadian pension fund managers during the crisis?

RESPONSE

In the case of the EGD plan, with the assistance of investment consultant Russell Investments, the plan asset mix was extensively reviewed culminating in the Enbridge Inc. Pension Committee approving a shift in asset mix in May 2007. This change reduced exposure to equities and reduced portfolio risk at a time when the pension plan had a significant surplus. This action helped protect the plan's funded status when equity markets collapsed in 2008. The Company continues to review and monitor plan performance on an ongoing basis.

The response of each Canadian pension manager to the crisis would have been tailored to the specific circumstances of the plan under their management, thus EGD is not in a position to comment on this.

Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #11

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

Ref: Ex. B /Tab 3/ Sch 1/

Paragraph 25 speaks about the plan's funding requirement of $18.9 million. Please comment on whether it is typical practice in the Canadian pension plan industry that when a plan is in a deficit position, its members' contributions are adjusted upwards to fully account for the shortfall. What is the role of the corporation overseeing the pension fund when a plan is in a deficit position and requires additional funding? Does the corporation typically contribute to the funding shortfall?

RESPONSE

The vast majority of private sector pension plans in Canada do not require additional employee contributions to fund plan deficits arising for reasons such as poor financial performance. The EGD plan is no different, in that, it is a non-contributory plan and does not require employee (or member) contributions even when the plan is in a deficit.

When a private sector pension plan is in a deficit position, cash contributions are required to fund the deficit in accordance with applicable provincial pension legislation. For private sector pension plans, such contributions are generally made by the plan sponsor.

Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #12

INTERROGATORY

ISSUE 10 – Z FACTOR - PENSION FUNDING

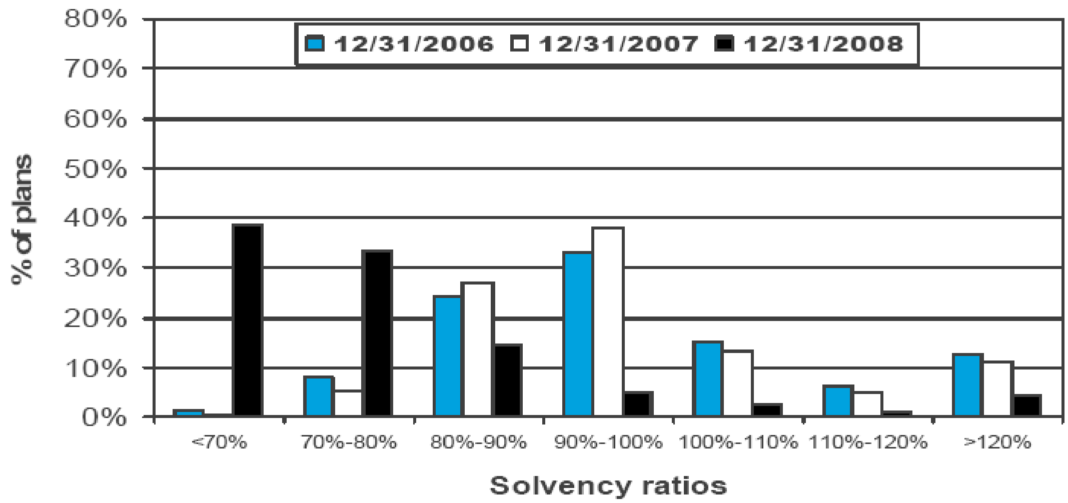
Ref: Ex. B /Tab 3/ Sch 1/

If available, please provide the 2007, 2008 and 2009 performance statistics for Canadian pension plans.

RESPONSE

The EGD RPP had a wind-up ratio of 120.6% and 90.9% as at December 31, 2007 and December 31, 2008, respectively. These wind-up ratios place the plan comfortably in the top quartile of funded plans in Canada. As can be seen in the chart below, approximately 11% of plans had a ratio higher than 120% at December 31, 2007 and 13% of plans had a ratio higher than 90% at December 31, 2008. This demonstrates that despite the economic turmoil in the past year, the EGD plan continues to be well funded relative to its peers.

The data for 2009 is not yet available to EGD.



Witnesses: J. Haberbusch
N. Kishinchandani

BOARD STAFF INTERROGATORY #13

INTERROGATORY

ISSUE 11 – Z FACTOR CROSSBORES

Ref: Ex. B /Tab 3/ Sch 2/

Paragraph 4 states that trenchless technologies at Enbridge have been in use since 1970. It also indicates that such technologies are known to crossbore sewer lines. Given this history, is there any reason that Enbridge would not have been aware of the risks well before the 5 year IRM rate settlement was established? In other words, has the crossbore risk been known to Enbridge for some time preceding the IRM agreement? Has Enbridge ever established a budget to manage the crossbore risk?

RESPONSE

Enbridge was aware of the possibility of a crossbore occurring in its franchise territory prior to the IRM period, however, the Company never established a budget to manage the crossbore risk prior to the IR period. As explained at Exhibit B, Tab 3, Schedule 2, it is only in the past couple of years that the magnitude of the issue, and the need to take immediate steps to address it, has become apparent.

The first time that Enbridge established any budget to specifically address crossbore issues was in 2008. The proposed budget for 2010, as presented in Exhibit B, Tab 3, Schedule 2, reflects the increased attention and activity related to the customer communication and safety initiatives which has caused the forecast of costs related to crossbore issues to pierce the Z-factor threshold.

Witnesses: C. Clark
L. Lawler

BOARD STAFF INTERROGATORY #14

INTERROGATORY

ISSUE 15 – OTHER ISSUES – TAX RATE AND RULE CHANGES

Ref: Ex. C /Tab 1/ Sch 4/

What is the impact of the government's proposed Harmonized Sales Tax on the budgeted 2010 utility earnings?

RESPONSE

EGD does not currently track sales tax separately within its actual or budgeted financials. EGD is currently in the process of analyzing various requirements and impacts of the proposed Harmonized Sales Tax, including the costs to the Company from required system and other related changes and estimating what, if any, impact there might be to earnings. Please see the response to BOMA Interrogatory #10 at Exhibit I, Tab 3, Schedule 10 for a further discussion of the potential impact of the proposed HST.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #15

INTERROGATORY

ISSUE 16 – SERVICE QUALITY REPORTING

Ref: Ex. C /Tab 1/ Sch 5/

Please file the benchmarks and the results of all the SQRs relating to 2007 and 2008. If available, please include the preliminary estimates for 2009.

RESPONSE

The benchmarks and the results listed in the table below address the following Service Quality Requirements:

S.2.1.9.A.1 Call Answering Service Level (CASL);
S.2.1.9.A.2 Abandon Rate (AR);
S.2.1.9.C.1 Meter Reading Performance Measurement (MRPM);
S.2.1.9.D.1 Appointments Met Within the Designated Time Period (AMWDTP);
S.2.1.9.D.2 Time to Reschedule Missed Appointment (TRMA);
S.2.1.9.E.1 Percentage of Emergency Calls Responded Within One Hour (ECRWOH);
S.2.1.9.F.1 Number of Days to Provide a Written Response (NDPAWR); and
S.2.1.9.G.1 Number of Days to Reconnect a Customer (NDTRAC).

Witnesses: T. Ferguson
K. Lakatos-Hayward
B. Visnjevac

Year	**2007**	**2008**	**2009**
CASL Target	75.0%	75.0%	75.0%
CASL Actual	77.2%	76.0%	74.1%
AR Target	10.0%	10.0%	10.0%
AR Actual	3.6%	3.7%	7.2%
MRPM Target	**0.5%**	**0.5%**	**0.5%**
MRPM Actual	**0.57%**	**0.69%**	**0.47%**
AMTWDTP Target	85%	85%	85%
AMTWDTP Actual	89.40%	93.70%	97.40%
TRMA Target	**100%**	**100%**	**100%**
TRMA Actual	**57.70%**	**62.80%**	**97%**
ECRWOH Target	90%	90%	90%
ECRWOH Actual	91.40%	94.20%	96.30%
NDPAWR Target	80%	80%	80%
NDPAWR Actual	100%	100%	100%
NDTRAC Target	85%	85%	85%
NDTRAC Actual	98%	97.70%	95.50%

In addition, the Company also confirms that it continues to maintain a Quality Assurance Program as per the Service Quality Requirement for Billing Performance Audits (S.2.1.9.B.1). This Quality Assurance Program validates billing charges when large variances in customer's consumption appear. Please refer to Appendix 1 and 2 for the results of the program for 2007 and 2008 respectively. 2009 results will be filed with the Board in April 2010.

The results for 2009 are preliminary as of February 1, 2009. The final results are going to be filed with the Board in April 2010.

As the table shows, actual performance for most metrics exceeds the target.

Witnesses: T. Ferguson
K. Lakatos-Hayward
B. Visnjevac

S.2.1.9.B – BILLING PERFORMANCE

S.2.1.9.B.1 AUDITS

INSTRUCTION:

The utility is required to have a verifiable Quality Assurance Program ("QAP") in place. Manual checks must be done to validate billing data when meter reads fall outside criteria (as set by the QAP) for excessively high or low usage.

a. Please mail or courier your company's current QAP to the OEB, attention Board Secretary with a copy to the Chief Regulatory Auditor and referring to S.7.3.2.1 of GDAR.

b. State when letter a) was mailed or couriered: ___________ (yyyy-mm-dd)

c. Does the QAP include criteria to validate data when meter reads are excessively high or low? Yes X___ No____

d. In **TABLE A,** please list the criteria.

e. Please fill in columns 1 to 7 of **TABLE B**. (see next tab)

	TABLE A
Number	**Criteria**
1	A random set of production bills is manually reviewed, based on a predefined set of billing data (ie. Accounts on budget billing, accounts on pay-per-use, accounts on pre-authorized payment, etc.), every billing day to ensure accuracy. The set of production bills consists of residential and commercial customer bills.
2	All bills whose consumption increases by 100% or more during the heating season (and 200% or more during the non heating season) when compared to the previous month are automatically reported each billing day and are reviewed manually for accuracy.
3	All bills whose gas charges are $1,000 or more are automatically reported each billing day and are reviewed manually for accuracy.
4	All bills whose meter readings indicate that there has been no gas consumption for two months (and the meter is still active) are automatically reported each billing day and are reviewed manually for accuracy. The customer is provided with an estimated bill (based on previous history) to avoid a potential large adjustment should the meter be deemed defective following the investigation. The customer is advised on the estimated bill that an investigation is underway.
5	Random audits of billing functions are performed to monitor billing performance.

Month (Calendar 2007)	Total Number of Billings (1)	Total Number of Manual Checks Done as per QAP (2)	Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage Vs. QAP Criteria (3)	Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage Vs. QAP Criteria (5)	Number of Random Audits Performed on Data Quality and Billing Accuracy (7)
Jan.	1,847,218	60891	3,490	1,613	907
Feb.	1,677,815	53542	3,771	1,520	1,015
Mar.	1,843,801	70223	4,879	1,726	985
Apr	1,722,984	53794	3,881	1,861	1,035
May	1,911,759	54445	4,308	2,656	1,037
Jun.	1,821,355	47539	4,958	3,230	983
Jul.	1,836,284	53798	5,296	5,135	1,026
Aug.	1,929,515	54336	7,391	5,945	983
Sept.	1,646,123	49139	5,034	3,752	987
Oct.	1,917,471	53509	3,821	3,466	1,040
Nov.	1,936,674	42913	3,109	1,563	985
Dec.	1,660,942	42595	3,122	841	965
TOTAL	**21,751,941**	**636,724**	**53,060**	**33,308**	**11,948**

Brief Explanation for Excessively High Usage (In 100 Words or less) (4)

1. Bills that exceed our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly (e.g. backwards or digits like and 8 or 6 may have been visually misread).
3. An actual read could be higher following a number of estimates.
4. The historical usage on the account might that suggest that the customer's usage increases at a particular times each year. (eg. Pool heaters)
5. The customer has installed additional and/or upgraded gas appliances.

Brief Explanation for Excessively Low Usage (in 100 Words or less) (6)

1. Bills that are below our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly e.g. backwards or digits like and 8 or 6 may have been visually misread.
3. An actual read could be lower following a number of estimates.
4. The historical usage on the account might that suggest that the customer's usage is reduced or stops altogether for certain periods each year.
5. The customer has removed or discontinued use of gas appliances.

S.2.1.9.B – BILLING PERFORMANCE

S.2.1.9.B.1 AUDITS

INSTRUCTION:

The utility is required to have a verifiable Quality Assurance Program ("QAP") in place. Manual checks must be done to validate billing data when meter reads fall outside criteria (as set by the QAP) for excessively high or low usage.

a. Please mail or courier your company's current QAP to the OEB, attention Board Secretary with a copy to the Chief Regulatory Auditor and referring to S.7.3.2.1 of GDAR.

b. State when letter a) was mailed or couriered: ___________ (yyyy-mm-dd)

c. Does the QAP include criteria to validate data when meter reads are excessively high or low? Yes_X__ No____

d. In **TABLE A,** please list the criteria.

e. Please fill in columns 1 to 7 of **TABLE B**. (see next tab)

	TABLE A
Number	**Criteria**
1	A random set of production bills is manually reviewed, based on a predefined set of billing data (ie. Accounts on budget billing, accounts on pay-per-use, accounts on pre-authorized payment, etc.), every billing day to ensure accuracy. The set of production bills consists of residential and commercial customer bills.
2	All bills whose consumption increases by 100% or more during the heating season (and 200% or more during the non heating season) when compared to the previous month are automatically reported each billing day and are reviewed manually for accuracy.
3	All bills whose gas charges are $1,000 or more are automatically reported each billing day and are reviewed manually for accuracy.
4	All bills whose meter readings indicate that there has been no gas consumption for two months (and the meter is still active) are automatically reported each billing day and are reviewed manually for accuracy. The customer is provided with an estimated bill (based on previous history) to avoid a potential large adjustment should the meter be deemed defective following the investigation. The customer is advised on the estimated bill that an investigation is underway.
5	Random audits of billing functions are performed to monitor billing performance.

Month (Calendar 2007)	Total Number of Billings (1)	Total Number of Manual Checks Done as per QAP (Volume includes: test bills, pull bills, LVB bills) (2)	Total Number of Manual Checks Done When Meter Reads Show Excessively High Usage Vs. QAP Criteria (3)	Total Number of Manual Checks Done When Meter Reads Show Excessively Low Usage Vs. QAP Criteria (5)	Number of Random Audits Performed on Data Quality and Billing Accuracy (7)
Jan.	1,964,096	38,215	3,061	1,073	925
Feb.	1,785,017	19,618	2,624	928	1,035
Mar.	1,781,114	27,951	2,410	1,019	1,005
Apr	2,072,317	37,830	4,805	1,603	1,058
May	1,894,701	31,039	5,403	1,955	1,058
Jun.	1,889,816	34,581	4,316	3,268	1,002
Jul.	1,998,998	41,485	5,261	3,803	1,047
Aug.	1,907,421	40,547	6,091	4,062	1,003
Sept.	1,812,064	37,674	5,142	3,648	1,007
Oct.	2,029,557	35,732	4,064	2,569	1,061
Nov.	1,934,807	28,441	2,828	1,388	1,005
Dec.	1,849,827	35,195	3,175	1,102	984
TOTAL	**22,919,735**	**408,308**	**49,180**	**26,418**	**12,190**

Brief Explanation for Excessively High Usage (In 100 Words or less)

1. Bills that exceed our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly (e.g. backwards or digits like and 8 or 6 may have been visually misread).
3. An actual read could be higher following a number of estimates.
4. The historical usage on the account might that suggest that the customer’s usage increases at a particular times each year. (eg. Pool heaters)
5. The customer has installed additional and/or upgraded gas appliances.

Brief Explanation for Excessively Low Usage (in 100 Words or less)

1. Bills that are below our parameters are manually verified or adjusted before mailing to the customer.
2. The meter might have been read incorrectly e.g. backwards or digits like and 8 or 6 may have been visually misread.
3. An actual read could be lower following a number of estimates.
4. The historical usage on the account might that suggest that the customer’s usage is reduced or stops altogether for certain periods each year.
5. The customer has removed or discontinued use of gas appliances.

APPRO INTERROGATORY #1

INTERROGATORY

Exhibit B, Tab 3, Schedule 1. Enbridge has requested that a Y factor be established in the amount of $18.9 million related to the company's pension plan. At paragraph 12, Enbridge notes that this is made up of an estimate from Mercer of $17.1 million to cover the plan deficit (as at December 3 1, 2009), plus a further $1.8 million that is required to be paid into the Pension Benefits Guarantee Fund (PBGF). At paragraph 14, Enbridge notes that the most recent update from Mercer is that the contributions to cover the plan's deficit could drop to $1.5 million and the premium related to the PBGF is now $1.5 million.

a. Please provide a copy of the Mercer report showing the calculations for the plan deficit as of December 3, 2008, as well as the update.
b. Does Enbridge have a more recent estimate of the projected pension deficit as of December 31, 2009 from Mercer, if so please file the report and the estimate
c. Enbridge notes in paragraph 12 that the PBGF is $1.8 million, but that payment has been reduced to $1.5 million in paragraph 14. Please reconcile these differences and provide a calculation that illustrates the $1.5 million liability
d. Please provide a copy of the appropriate sections of the Act, Regulations or other documents that support the liability of the $1.5 million in PBGF funding and the calculation referenced in c. above.
e. Please provide similar information that supports the requirement to fund the deficit.
f. Please explain why the company is asking for a Z factor to fund a deficit amount based on the estimate prepared as of December 31, 2008 that is substantially higher than a more recent estimate, especially in light of the rebound of the financial markets in 2009?

RESPONSE

a) Please find attached a copy of the 2008 valuation report from Mercer. It is important to note the comments on page 3 that this valuation was not filed with the Financial Services Commission of Ontario, is for management information only. It is part of Enbridge's governance process to have actuarial valuations done each year, even though they may not be filed each year.

Witnesses: J. Haberbusch
N. Kishinchandani

b) The Company does not have a more recent estimate of the projected pension deficit, as at December 31, 2009. This is expected to be available no earlier than April 2010.

c) The 2010 PBGF premium of $1.8m is based on the December 31, 2008 valuation, factoring in the service cost and interest cost for 2009, for an estimated wind-up deficiency of approximately $88 million at the end of 2009. This calculation does not factor in any actual experience in 2009. On the other hand, the $1.5m is based on Mercer's best estimate of asset and liability values using August 31, 2009 data. These calculations reflect a wind-up deficiency of $75.5 million. The PGBF premium is 2% of such wind-up deficiency, an amount of $1.5 million.

d) *Ontario Pension Benefits Regulations* Section 37, Subsections (4) and (5)

(4) Except for a plan to which subsection (6) applies, the amount of the annual assessment shall be equal to the lesser of, (O. Reg. 413/07, s. 4(1).)

(a) the sum of,

(i) the lesser of,

(A) the sum of $1 for each person who is an Ontario plan beneficiary at the end of the plan fiscal year immediately preceding the assessment date plus the amount calculated under subsection (5), or

(B) $100 multiplied by the number of persons who were Ontario plan beneficiaries at the end of the plan fiscal year immediately preceding the assessment date, and

(ii) zero, or, if an election under subsection 5(18) is in effect on the assessment date, 2 per cent of the amount by which, (A) the additional liability that would result if, on the valuation date of the last report filed or submitted on or before the assessment date under any of section 3, section 4, subsection 5.3(1) or section 14 for the plan, all plant closure benefits and permanent layoff benefits under the plan were payable for those members in Ontario who, on that date, met the age and service requirements for such benefits, exceeds, (B) the amount, if any, by which the amount determined under clause (b) in the definition of PBGF assessment base exceeds the PBGF liabilities, both determined as of the valuation date referred to in subclause (A); and

(b) $4,000,000.

(5) The amount referred to in sub-subclause (4)(a)(i)(A) shall be the sum of,

(a) 0.5 per cent of any portion of the PBGF assessment base that is less than 10 per cent of the PBGF liabilities;

Witnesses: J. Haberbusch
N. Kishinchandani

(b) 1 per cent of any portion of the PBGF assessment base that is 10 per cent or more but less than 20 per cent of the PBGF liabilities; and

(c) 1.5 per cent of any portion of the PBGF assessment base that is 20 per cent or more of the PBGF liabilities.

e) *Ontario Pension Benefits Regulations* Section 5, Subsection (1)

(1) Except as otherwise provided in this section and in sections 4, 5.1 and 7, the special payments required to be made after the initial valuation date under clause 4(2)(c) shall be not less than the sum of,

(a) any special payments remaining to be paid with respect to any initial unfunded liability or experience deficiency within the meaning of Regulation 746 of Revised Regulations of Ontario, 1980 as it read on the 31st day of December, 1987, after reducing the sum of the initial unfunded liability and experience deficiency by the amount of any unused actuarial gains existing on the 31st day of December, 1987;

(b) with respect to any going concern unfunded liability not covered by clause (a), the special payments required to liquidate the liability, with interest at the going concern valuation interest rate, by equal monthly instalments over a period of fifteen years beginning on the valuation date of the report in which the going concern unfunded liability was determined;

(c) with respect to each solvency deficiency redetermined under subsection (3), the special payments required to liquidate the redetermined solvency deficiency, with interest at the rates used in calculating the solvency liabilities in the first report filed or submitted under section 3, 4 or 14 with a valuation date after the Regulation date, by equal monthly instalments over the period beginning on the valuation date of the report in which the solvency deficiency was determined and ending on the 31st day of December, 2002;

(d) with respect to each solvency deficiency arising before the Regulation date that is not redetermined under subsection (3), the special payments required to liquidate the solvency deficiency, with interest at the rates described in subsection (2), by equal monthly instalments over the period beginning on the valuation date of the report in which the solvency deficiency was determined and ending on the 31st day of December, 2002 or an earlier date; and

(e) with respect to any solvency deficiency arising on or after the Regulation date, the special payments required to liquidate the solvency deficiency, with interest at the rates described in subsection (2), by equal monthly instalments over the period beginning on the valuation date of the report in which the solvency deficiency was determined and ending on the 31st day of December, 2002, or five years, whichever is longer.

Witnesses: J. Haberbusch
N. Kishinchandani

f) Only a formal year-end valuation can form the basis for determination of contributions. Interim estimates provide guidance, but do not qualify to form the basis for determination of such contributions. The Company acknowledges that the performance of financial markets in 2009 will likely result in the final contribution requirement being at the lower end of the contribution range of $3.0 million and $18.9 million noted in the evidence, however a final determination can only be made once the valuation report at December 31, 2009 becomes available in April 2010.

Witnesses: J. Haberbusch
N. Kishinchandani

June 30, 2009

Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2008

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Canada Revenue Agency Registration Number: 0242016

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Summary of Results

Going-Concern Financial Position	12.31.2008	12.31.2007
Actuarial value of assets	$634,733,000	$809,033,000
Actuarial liability	$637,066,600	$622,321,000
Funding excess (funding shortfall)	($2,333,600)	$186,712,000

Solvency Financial Position	12.31.2008	12.31.2007
Solvency assets	$635,159,000	$808,433,000
Solvency liability	$611,685,300	$671,541,700
Solvency excess (deficiency)	$23,473,700	$136,891,300
Ratio of solvency assets to solvency liabilities	104%	120%

Wind-Up Position	12.31.2008	12.31.2007
Wind-up assets	$634,133,000	$808,433,000
Wind-up liability	$696,582,700	$671,541,700
Wind-up excess (deficiency)	($62,449,700)	$136,891,300
Transfer ratio	91%	100%

Funding Requirements (annualised) – DB Component[1]	**2009**	**2008**
Total current service cost	$14,848,700	$15,733,800
Estimated members' required contributions	$0	$0
Estimated employer's current service cost	$14,848,700	$15,733,800
Employer's current service cost as a percentage of members' pensionable earnings		
▪ Non-SMEs	11.61%	12.52%
▪ SMEs	22.36%	22.64%
Minimum special payments	$230,000	$0
Estimated minimum employer contributions for year	$15,078,700	$0
Estimated maximum employer contributions for year	$77,298,700	$0

Funding Requirements (annualised) – DC Component	**2009**	**2008**
Estimated employer's current service cost	$1,430,300	$1,397,700
Employer's current service cost expressed as a percentage of DC members' pensionable earnings	5.83%	5.66%

[1] If valuation report is filed.

2

Introduction

Report on the Actuarial Valuation as at December 31, 2008

To: Enbridge Gas Distribution Inc.

At your request, we have conducted an actuarial valuation of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "Plan") as at December 31, 2008. We are pleased to present the results of the valuation.

The purposes of this valuation are to determine:

- the funded status of the Plan as at December 31, 2008 on going-concern, solvency and wind-up bases, and
- the minimum and maximum funding requirements from 2009 if this report is filed.

The information contained in this report was prepared for Enbridge Gas Distribution Inc. for its internal use in connection with our actuarial valuation of the Plan. This report is not intended or necessarily suitable for other purposes.

It is our understanding that this report will not be filed with the Financial Services Commission of Ontario or with Canada Revenue Agency. Therefore, the minimum funding requirements for the Plan will continue to be those determined and filed as of December 31, 2006. The funding requirements described in this report are to be considered for informational purposes only. Information on funding requirements assuming this valuation is not filed can be found in our Report on the Actuarial Valuation for Funding Purposes as at December 31, 2006. Further, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2009 or as at the date of an earlier amendment to the Plan, in accordance with the minimum requirements of the *Pension Benefits Act (Ontario).*

This valuation reflects the provisions of the Plan as at December 31, 2008. The Plan has been amended since the date of the previous valuation to reflect housekeeping items. This amendment had no material impact on Plan liabilities. A summary of the Plan provisions is provided in Appendix D.

We have used the same going-concern valuation assumptions and methods as were used for the previous valuation as at December 31, 2007 except:

- the assumed investment return was changed from 6.00% per year to 5.75% per year,
- the assumed inflation was changed from 2.25% per year to 2.00% per year, which corresponds to the assumed increase to pensions in payment changing from 1.125% per year to 1.00% per year for Non-Contributory and SME service, and from 1.238% per year to 1.10% per year for Contributory service,
- the assumed increase in pensionable earnings was changed from 5.00% per year to 3.50% per year, and
- the assumed increases in the YMPE and maximum pension permitted under the *Income Tax Act* after 2009 were changed from 3.00% per year to 2.50% per year.

These changes have resulted in a decrease of $9,916,200 in actuarial liability and a decrease of $1,300,100 in the employer current service cost.

The solvency and wind-up assumptions have been updated to reflect market conditions at the valuation date. In addition, the methodology used to calculate the solvency liability has been revised.

The assumptions and methods used for the purposes of this valuation are described in detail and compared to the assumptions and methods from the previous valuation in Appendix B. All assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

A new Canadian Institute of Actuaries Standard of Practice for determining pension commuted values ("CIA Standard") became effective on April 1, 2009. The new CIA Standard changes the assumptions to be used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. As permitted by the Financial Services Commission of Ontario, the financial impact of the new CIA standard has therefore been reflected in this actuarial valuation.

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the Plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("Monsanto"), thereby upholding the requirement to distribute surplus on partial plan wind-ups under The *Pension Benefits Act (Ontario)*. The decision has retroactive application. Other than the Telesis partial wind-up, we are unaware of any partial plan wind-up having been declared in respect of the Plan. In preparing this actuarial valuation, we have assumed that all Plan assets are available to cover the Plan liabilities presented in this report. The subsequent declaration of a partial wind-up of the Plan in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on Plan assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the Superintendent of Financial Services to declare partial wind-ups and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the Superintendent might declare a partial wind-up in respect of events in the Plan's history.

Since the valuation date there have been significant fluctuations in the financial markets. We have reflected the financial position of the Plan as of the valuation date, and have not taken into account any experience after the valuation date.

After checking with representatives of Enbridge Gas Distribution Inc., to the best of our knowledge there have been no other events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

This report has been prepared, and our opinions give, in accordance with accepted actuarial practice. It has also been prepared in accordance with the funding and solvency standards set by the *Pension Benefits Act (Ontario)*.

Respectfully submitted,

Chris Heller	Malcolm Kern
FCIA, FSA	FCIA, FSA
June 30, 2009	June 30, 2009
Date	Date

Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates
Registration number with the Financial Services Commission of Ontario and with the Canada Revenue Agency: 0242016

This valuation report may not be relied upon for any purpose other than those explicitly noted above or by any party other than Enbridge Gas Distribution Inc. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

To prepare this report, *actuarial assumptions*, as described in Appendix B, are used to select a single ongoing or going-concern scenario from the range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in regulatory requirements, plan experience, changes in expectations about the future and other factors.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

3

Financial Position of the Plan

Valuation Results – Going-Concern Basis

When conducting a valuation on a going-concern basis, we determine the relationship between the respective values of assets and accumulated benefits, assuming the Plan will be maintained indefinitely.

Financial Position on a Going-Concern Basis

The results of the valuation as at December 31, 2008, in comparison with those of the previous valuation as at December 31, 2007, are summarized as follows:

Financial Position - Going-Concern Basis

	12.31.2008	**12.31.2007**
Actuarial value of assets		
▪ defined benefit component	$628,233,000	$802,284,000
▪ defined contribution component	$6,500,000	$6,749,000
Total assets	$634,733,000	$809,033,000
Actuarial liability		
Present value of accrued benefits for:		
▪ active members	$304,268,200	$311,460,500
▪ suspended members	$11,072,600	$13,726,300
▪ pensioners and survivors	$306,792,600	$283,125,100
▪ deferred pensioners	$8,433,200	$7,260,100
Total defined benefit liability	$630,566,600	$615,572,000
Total defined contribution liability	$6,500,000	$6,749,000
Total liability	$637,066,600	$622,321,000
Funding excess (funding shortfall)	($2,333,600)	$186,712,000
Defined benefit assets over defined benefit liabilities	99%	130%

Reconciliation of Financial Position

The Plan's financial position, a funding shortfall of $2,333,600 as at December 31, 2008, is reconciled with its previous position, a funding excess of $186,712,000 as at December 31, 2007, as follows:

Reconciliation of Financial Position

Funding excess (funding shortfall) as at 12.31.2007	$186,712,000
Interest on funding excess (unfunded liability) at 6.00% per year to 12.31.2008	$11,202,700
Net experience gains (losses) over 2008*	($192,247,200)
Defined benefit component contributions drawn from previous funding excess	($16,194,500)
Defined contribution component contributions drawn from previous funding excess	($1,475,400)
Net impact of changes in assumptions	$9,916,200
Net impact of other elements of gains and losses	($247,400)
Funding excess (funding shortfall) as at 12.31.2008	($2,333,600)

* Net experience gains (losses) from specific sources are detailed on the following page.

Plan Experience

The main assumptions are compared with actual experience since the previous valuation as at December 31, 2007, as follows:

Plan Experience

	Assumption	**Actual 2008**	**Impact Gain (loss)**
Net investment return	6.00% /year	-18.40% /year	($192,256,600)
Increases in pensionable earnings	5.00% /year	4.02% /year	$4,158,200
Increases in the YMPE	3.00% /year	3.12% /year	
Retirements			
▪ number	73 retirements	65 retirements	$105,600
▪ average age	61 years	60 years	
Indexation of pensions	2.25% inflation	3.49% inflation	($2,002,500)
Terminations of employment	58 terminations	55 terminations	($1,050,800)
Mortality:			
▪ pre-retirement	4 deaths	3 deaths	($161,200)
▪ post-retirement	43 deaths	46 deaths	($1,039,900)
Net experience gains (losses)			($192,247,200)

Valuation Results – Solvency Basis

When conducting a solvency valuation, we determine whether or not the Plan's assets exceed its liabilities on a solvency basis, determined in accordance with the *Pension Benefits Act (Ontario).* The values of the Plan's assets and liabilities on a solvency basis are related to the values that would apply if the Plan were wound up and the obligations were settled on the valuation date. The circumstances in which the Plan wind-up is assumed to have taken place are described in detail in Appendix B.

For the purpose of determining the solvency liabilities, we have assumed that Enbridge Gas Distribution Inc. voluntarily decides to wind-up the Plan. In accordance with the *Pension Benefits Act (Ontario),* we have not included the value of certain benefits that may be contingent upon the circumstances of the postulated plan wind-up. Specifically, cost-of-living adjustments have been excluded from the solvency liabilities.

Financial Position on a Solvency Basis

The Plan's solvency position as at December 31, 2008 in comparison with that of the previous valuation as at December 31, 2007 is determined as follows:

Solvency Position

	12.31.2008	**12.31.2007**
Assets – defined benefit component		
▪ market value of assets	$628,233,000	$802,284,000
▪ termination expense provision	($600,000)	($600,000)
1. Solvency assets – defined benefit component	$627,633,000	$801,684,000
Present value of special payments for next five years	$1,026,000	$0
2. Adjusted solvency assets – defined benefit component	$628,659,000	$801,684,000
Assets – defined contribution component		
3. Solvency assets – defined contribution component	$6,500,000	$6,749,000
Actuarial liability – defined benefit component		
Present value of accrued benefits for:		
▪ active members	$328,080,200	$320,982,800
▪ suspended members	$9,982,700	$11,425,900
▪ pensioners and survivors	$342,657,200	$323,757,100
▪ deferred pensioners	$9,362,600	$8,626,900
4. Liabilities before exclusion of benefits	$690,082,700	$664,792,700
5. Value of excluded benefits	($84,897,400)[2]	($0)[3]
6. Solvency liabilities – defined benefit component	$605,185,300	$664,792,700
7. Solvency liabilities – defined contribution component	$6,500,000	$6,749,000
Solvency excess (deficiency) created as at valuation date (2. - 6.)	$23,473,700	$136,891,300
Transfer ratio (1. ÷ 4.)	0.91	1.00
Ratio of solvency assets to solvency liabilities (2. ÷ 6)	1.04	1.21

[2] Cost-of-living adjustments have been excluded from the December 31, 2008 solvency liabilities.

[3] No benefits that would be contingent on plan wind-up were excluded from December 31, 2007 solvency liabilities.

Payment of Benefits

The transfer ratio revealed in the last filed valuation as at December 31, 2006 was greater than 1, while the transfer ratio as at December 31, 2008 is 0.91. If the Plan administrator knows (or ought to know) that the transfer ratio subsequently drops below 0.90, the administrator must take action to meet the requirements of the *Pension Benefits Act (Ontario)* to allow for the full payment of benefits. Otherwise, the Plan administrator should take the actions prescribed in the *Act*.

Financial Position on a Wind-up Basis

The Plan's hypothetical wind-up position as of December 31, 2008, assuming circumstances producing the maximum wind-up liabilities on the valuation date, is determined as follows:

Wind-up Position

	12.31.2008	**12.31.2007**
Market value of assets		
▪ defined benefit component	$628,233,000	$802,284,000
▪ defined contribution component	$6,500,000	$6,749,000
▪ termination expense provision	($600,000)	($600,000)
Wind-up assets	$634,133,000	$808,433,000
Present value of accrued benefits for:		
▪ active members	$328,080,200	$320,982,800
▪ suspended members	$9,982,700	$11,425,900
▪ pensioners and survivors	$342,657,200	$323,757,100
▪ deferred pensioners	$9,362,600	$8,626,900
Total defined benefit liability	$690,082,700	$664,792,700
Total defined contribution liability	$6,500,000	$6,749,000
Total wind-up liability	$696,582,700	$671,541,700
Wind-up excess (deficiency)	($62,449,700)	$136,891,300

Impact of Plan Wind-Up

In our opinion, the value of the Plan's assets would be less than its actuarial liabilities if the Plan were to be wound up on the valuation date.

Specifically, actuarial liabilities would exceed the market value of assets by $62,449,700. This calculation includes a provision for termination expenses expected to be paid from the fund.

4

Funding Requirements

Current Service Cost

The estimated value of the benefits that will accrue on behalf of Senior Management Employees (SMEs) and non-SMEs accruing defined benefit service during 2009, in comparison with the corresponding value determined in the valuation as at December 31, 2007, is summarized below:

Employer's Current Service Cost – Defined Benefit Component

		2009	2008
Current service cost of non-SME members		$13,947,000	$14,914,900
Current service cost of SME members		$901,700	$818,900
Total current service cost		$14,848,700	$15,733,800
Estimated members' required contributions		$0	$0
Estimated employers' current service cost		$14,848,700	$15,733,800
Total base pensionable earnings excluding pensionable bonuses for the year following valuation date - non-SME members		$120,156,000	$119,172,000
Total base pensionable earnings excluding pensionable bonuses for the year following valuation date - SME members		$4,033,000	$3,617,000
Total members' pensionable earnings, excluding pensionable bonuses for year following valuation date		$124,189,000	$122,789,000
Employers' current service cost expressed as a percentage of members' pensionable earnings, excluding pensionable bonuses	Non-SMEs	11.61%	12.52%
	SMEs	22.36%	22.64%
	Aggregate	11.96%	12.81%

An analysis of the changes in the employer's current service cost for the defined benefit component follows:

Changes in Employer's Current Service Cost – Defined Benefit Component

	Non – SMEs	SMEs
Employers' current service cost as at 12.31.2007	12.52%	22.64%
Demographic changes	0.04%	-0.13%
Changes in assumptions and methods	-0.95%	-0.15%
Employers' current service cost as at 12.31.2008	11.61%	22.36%

In addition, contributions are made to the defined contribution component of the Plan, subject to *Income Tax Act* maximums. The estimated value of benefits that will accrue on behalf of the active members accruing defined contribution benefits during 2009 is summarized below:

Employer's Current Service Cost – Defined Contribution Component

	2009	2008
Total current service cost	$1,430,300	$1,397,700
Employer's current service cost expressed as a percentage of members' pensionable earnings, excluding pensionable bonuses[4]	5.83%	5.66%

[4] The defined contribution service cost expressed as a percentage of pensionable earnings, including pensionable bonus, for 2008 and 2009 are 5.27% and 5.43%, respectively.

Special Payments

Going-concern Basis

No going-concern funding shortfall or special payments existed in the previous filed valuation. If this report were filed, then in accordance with the *Pension Benefits Act (Ontario)*, the going-concern funding shortfall of $2,333,600 would need to be amortized over a period not exceeding 15 years. As such, special payments would need to be established at $230,000 per year (payable monthly) until 2023 to amortize this going-concern funding shortfall.

Solvency Basis

No solvency special payments are required.

Total Special Payments

If this report were filed, the following minimum annual special payments, payable monthly, must be made to the Plan to eliminate the going-concern funding shortfall as at December 31, 2008 within the periods prescribed by the *Pension Benefits Act (Ontario).*

Minimum Annual Special Payments Payable Monthly

Type of Deficit	Effective Date	Special Payment	Last Payment
Funding shortfall	December 31, 2008	$230,000	2023
Total		$230,000	

Employer Contributions

Defined Benefit Component

As at December 31, 2008, there is a funding shortfall of $2,333,600 and solvency assets exceed solvency liabilities by $23,473,700, on the basis of the assumptions and methods described in this report.

Minimum Funding Requirements

As such, if this report is filed, we recommend the employers make minimum contributions to the Plan from 2009 as follows:

Minimum Employer Contributions

For current service see Appendix E – Current Service Cost for % of members' pensionable earnings by employer
Minimum annual special payments payable monthly for funding shortfall: $230,000

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for 2009 to be $15,078,700 if this report is filed. Assuming members' pensionable earnings grow at 3.5% per year, the minimum employers' contributions through 2011 would be as follows:

Estimated Annual Minimum Employers Contributions Until December 31, 2011

Year Ending	Current Service Cost	Minimum Special Payments	Minimum Employer's Contribution
December 31, 2009	$14,848,700	$230,000	$15,078,700
December 31, 2010	$15,368,400	$230,000	$15,598,400
December 31, 2011	$15,906,300	$230,000	$16,136,300

Contributions for current service must be made within 30 days following the month to which they apply. Special payments to eliminate a funding shortfall or solvency deficiency must be made in the month to which they apply.

The minimum contribution requirements based on this report exceed the minimum contribution requirements recommended in the previous valuation report. If this report were filed, the employers would be required to contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following December 31, 2008. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Maximum Eligible Contributions

The maximum eligible employer contribution is equal to the employer current service cost plus the greater of the funding shortfall and the wind-up deficiency. We have estimated the maximum eligible annual contribution for 2009 to be $77,298,400 as at December 31, 2008. The portion of this contribution representing the payment of the wind-up deficiency ($62,449,700) can be increased with interest at 4.68% per year, from December 31, 2008 to the date the payment is made.

Defined Contribution Component

The employer's defined contribution current service cost is determined as follows:

Development of Employer's Defined Contribution Current Service Cost

	Company Contribution Rate	Estimated Pensionable Earnings Including Pensionable Bonus	Estimated Current Service Cost
Members with less than 40 points	4.0%	$6,434,300	$257,400
Members with more than 40 points and less than 60 points	5.5%	$14,782,100	$813,000
Members with 60 points or more	7.0%	$5,141,700	$359,900
Total		$26,358,100	$1,430,300

Contributions for current service must be made monthly and within 30 days following the month to which they apply.

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Actuarial Opinion

With Respect to the Actuarial Valuation as at December 31, 2008 of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates Registration Number: 0242016

Based on the results of this valuation, we hereby certify that, as at December 31, 2008,

- The employers' defined benefit current service cost for 2009 and subsequent years up to the next actuarial valuation should be calculated for each employer as indicated in Appendix E as a percentage of members' pensionable earnings (excluding pensionable bonuses). The average defined benefit current service cost for 2009 is 11.96%.

- The employers' defined benefit current service cost for 2009 is estimated to be $14,848,700.

- The employers' defined contribution current service cost for 2009 is estimated to be $1,430,300.

- The Plan would be fully funded on a going-concern basis if its assets were augmented by $2,333,600. If this report were filed, in order to comply with the provisions of the *Pension Benefits Act (Ontario)* the funding shortfall must be liquidated by special payments at least equal to the amounts indicated, payable no less frequently than monthly and for the period set forth below:

Annual Funding Shortfall Special Payments Payable Monthly

Type of Deficit	Effective Date	Special Payment	Last Payment
Funding shortfall	December 31, 2008	$230,000	2023
Total		$230,000	

- The Plan has a solvency excess of $23,473,700 as at December 31, 2008. No special payments would be required for solvency purposes if this report were filed.

- We have not included in the solvency liabilities the value of certain benefits that may be contingent upon the circumstances of the postulated wind-up. The circumstances in which the Plan wind-up is assumed to have taken place are described in detail in Appendix B. Had the Plan wind-up been postulated without excluding the value of certain benefits, the solvency liability would have increased by $84,897,400. Specifically, actuarial liabilities would have exceeded Plan assets $62,449,700.

- The transfer ratio of the Plan is 0.91. The Prior Year Credit Balance is nil.

- In our opinion,

  - the data on which the valuation is based are sufficient and reliable for the purposes of the valuation,

  - the assumptions are, in aggregate, appropriate for the purposes of determining the funded status of the Plan as at December 31, 2008 on going-concern, solvency and wind-up bases, and determining the minimum funding requirements, and

  - the methods employed in this valuation are appropriate for the purposes of determining the funded status of the Plan as at December 31, 2008, on going-concern, solvency and wind-up bases, and determining the minimum funding requirements.

- This report has been prepared, and our opinions given, in accordance with accepted actuarial practice.

- All assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

Chris Heller	Malcolm Kern
FCIA, FSA	FCIA, FSA
June 30, 2009	June 30, 2009
Date	Date

Appendix A

Plan Assets

Sources of Plan Asset Data

The defined benefit assets of the Plan are held in trust by CIBC Mellon. The defined contribution assets of the Plan are held in trust by Sun Life Assurance Company of Canada.

We have relied upon audited financial statements provided by Enbridge Gas Distribution Inc. for the period from January 1, 2008 to December 31, 2008.

Reconciliation of Plan Assets

The pension fund transactions for the period from January 1, 2008 to December 31, 2008 are summarized as follows:

Reconciliation of Defined Benefit Plan Assets (Market Value)

	2008		
	DB	**DC**	**Total**
January 1	$802,284,000	$6,749,000	$809,033,000
PLUS:			
Employer contributions			
Current service	$0	$0	$0
Special payments	$0	$0	$0
Investment income	($139,131,000)	($1,525,000)	($140,656,000)
	($139,131,000)	($1,525,000)	($140,656,000)
LESS:			
Pensions paid	$25,673,000	$0	$25,673,000
Lump-sum refunds	$1,966,000	$157,000	$2,123,000
Investment expenses	$4,168,000	$0	$4,168,000
Other expenses	$1,680,000	$0	$1,680,000
Transfer to DC from DB	$1,433,000	($1,433,000)	$0
	$34,920,000	($1,276,000)	$33,644,000
December 31	$628,233,000	$6,500,000	$634,733,000

We have tested the pensions paid, the lump-sum refunds and the contributions for consistency with the membership data for the Plan members who have received benefits or accrued service. The results of these tests were satisfactory.

Investment Policy

The Plan administrator last revised its Statement of Investment Policies and Procedures effective May 2007. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the defined benefit component of the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints in the defined benefit asset mix, and the actual asset mix as at December 31, 2008, are provided for information purposes:

Distribution of the Market Value of the Defined Benefit Component of the Fund by Asset Class

	Investment Policy			Actual Asset Mix as at
	Minimum	**Target**	**Maximum**	**December 31, 2008**
Canadian equities	18%	21.0%	24%	20.9%
Foreign equities	22.5%	31.5%	40.5%	33.6%
Fixed income – universe	19.5%	32.5%	35.5%	42.1%
Fixed Income – real return	7%	10.0%	13%	
Infrastructure	2.0%	5.0%	8.0%	3.3%
Cash and short term assets	0%	0%	5%	0.1%
		100%		100%

Performance of Fund Assets – Defined Benefit Component

The average return on the market value of the assets, net of expenses, since the last valuation at December 31, 2007 was -18.40%. This rate is less than the assumed investment return of 6.00% by 24.40%.

Performance of Fund Assets – Defined Contribution Component

The average return on the market value of assets, net of expenses, since the last valuation at December 31, 2007 was -20.64%.

Appendix B

Actuarial Methods and Assumptions

Actuarial Valuations Methods – Going-Concern Basis

Valuation of Assets – Defined Benefit Component

We have used the market value of assets at the valuation date. The actuarial value of the defined benefit component's assets as at December 31, 2008 under this method is $628,233,000.

Valuation of Assets – Defined Contribution Component

Market values were used for the defined contribution assets.

Valuation of Actuarial Liabilities – Defined Benefit Component

Over time, the real cost to the sponsor of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going-concern valuation, we have continued to use the *projected unit credit actuarial cost method*. Under this method, we determine the actuarial present value of benefits accrued in respect of service prior to the valuation date, including ancillary benefits, based on projected final average earnings. This is referred to as the *actuarial liability*.

The *funding excess* or *unfunded liability*, as the case may be, is the difference between the actuarial value of assets and the actuarial liability. An unfunded liability will be amortized over no more than 15 years through special payments as required under the *Pension Benefits Act* (Ontario). A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the Plan or by legislation.

This actuarial funding method produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial funding method aims at keeping the Plan fully funded at all times. This promotes benefit security, once any unfunded liabilities and solvency deficiencies have been funded.

Current Service Cost – Defined Benefit Component

The *current service cost* is the actuarial present value of projected benefits to be paid under the Plan with respect to service during the year following the valuation date.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Employer's Contribution – Defined Benefit Component

Accordingly, the employer's contributions for this purpose are determined as follows:

Employer's Contributions

With a funding excess	With an unfunded liability
Current service cost	Current service cost
MINUS	PLUS
Any funding excess applied to cover the Employers' current service cost	Payments to amortize any unfunded liability

Valuation of Liabilities – Defined Contribution Component

For the purposes of the going-concern and solvency valuations, the market value of each individual member's account on December 31, 2008 represents the Plan's liability with respect to that member.

Current Service Cost – Defined Contribution Component

The employer's current service cost is determined in accordance with the terms of the Plan for each individual member, subject to any *Income Tax Act* maximums.

Defined Benefit Component Actuarial Assumptions – Going-Concern Basis

The actuarial value of benefits for the defined benefit component of the Plan is based on economic and demographic assumptions. At each valuation, we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them if necessary.

In this valuation, we have used the same assumptions as in the previous valuation, except as noted. The December 31, 2008 assumptions are based on best estimates with the exception of the investment return, which includes a margin for all contingencies. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations. For this valuation, we have used the following assumptions:

Economic Assumptions

Investment Return

We have assumed that the investment return on the market value of the fund will average 5.75% per year over the long term. We have based this assumption on an expected long-term return on the pension fund less an allowance for investment and administrative expenses, and less a margin for adverse deviation, as described below.

We have assumed a gross rate of return of 7.08% consistent with market conditions applicable on the valuation date based on estimated returns for each major asset class and the target asset mix in the Plan's investment policy. Additional returns of 0.18% are assumed to be achievable due to active management.

We have allowed for investment and administrative expenses of 0.45% per year.

We have also included a margin for adverse deviations from all sources of 1.03% per year.

For the previous valuation, the assumed investment return (net of expenses and a margin for adverse deviations) was 6.00%.

Expenses

The assumed investment return reflects an implicit provision for investment and administrative expenses, based on the average of such expenses over recent years.

Inflation

The benefits ultimately paid depend on the level of inflation. We have assumed inflation will be 2.00% per year. This assumption reflects our best estimate of future inflation considering the Bank of Canada's inflation target and market expectations of long-term inflation implied by the yields on nominal and real return bonds.

For the previous valuation, the assumed inflation was 2.25%

Increases in the YMPE

Since some of the benefits provided by the Plan depend on the final average Year's Maximum Pensionable Earnings (YMPE) under the Canada/Québec Pension Plan, it is necessary to make an assumption about increases in the YMPE. For this valuation, we have assumed that the YMPE will increase at the assumed rate of inflation of 2.00% per year plus an allowance of 0.50% per year for the effect of real economic growth and productivity gains in the Canadian economy. The total increase of 2.50% per year was applied from the 2009 level of the YMPE of $46,300.

For the previous valuation, the YMPE was assumed to increase by 3.00% per year.

Increases in the Maximum Pension Permitted under the Income Tax Act

The *Income Tax Act* stipulates that the maximum pension that can be provided under a registered pension plan will be increased to specified amounts up to 2009, and automatically, starting in 2010, in accordance with general increases in the average wage.

For this valuation, we have assumed that the maximum pension payable under the Plan will increase as specified in the *Income Tax Act* for 2009, and will increase starting in 2010 at the same rate as the YMPE, 2.50% per year.

For the previous valuation, the maximum pension limit was assumed to increase, starting in 2010, at 3.00% per year.

Increases in Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death, or termination of employment, we have taken the rate of pay at December 31, 2008 and assumed that such pensionable earnings will increase by 3.50% on April 1st each year.

This rate is based on:

- an inflation rate of 2.00% per year,
- productivity increases of 0.50% per year, and,
- merit and promotional increase component of 1.00% per year.

The current merit and promotional increases component is based on our best estimate of future merit and promotional increases considering current economic and financial market conditions. The experience indicates that these assumptions remain appropriate.

For the pervious valuation, pensionable earnings were assumed to increase by 5.00% per year.

Pensionable Bonuses

Since the benefits accrued by Senior Management Employees (SMEs) after December 31, 2007 and by non-SME members after June 30, 2001 are based on pensionable earnings plus 50% of actual bonuses received by the member, it is necessary to make an assumption about projected bonuses. For this valuation, actual bonuses for non-SME members have been estimated with an assumed target bonus rate of 12% for non-union members, and 4% for union members. For SME members, actual bonuses are assumed equal to that member's target bonus.

The projected actual bonuses described above were increased by 25% to reflect an expectation that an individual's target bonus at retirement may be higher than it is currently due to promotion, and that annual bonuses vary from year to year but only the best three out of the last five are included in the final average earnings calculation.

Indexation of Pensions in Payment

Pensions in payment are increased each year according to a formula related to increases in the Consumer Price Index (CPI).

For this valuation, we have assumed that the CPI will increase at the assumed rate of inflation of 2.00% per year. Consequently, pensions in payment to members who retire in respect of the Contributory portion of the defined benefit component of the Plan are assumed to increase annually at the rate of 1.10% per year, being 55% of the increase in the CPI. Pensions in payment to members who retire in respect of the Non-Contributory portion and SME portion of the defined benefit component of the Plan are assumed to increase annually at the rate of 1.00% per year, being 50% of the increase in the CPI.

For the previous valuation, we had assumed CPI would increase at a rate of 2.25% per year. Therefore, pensions in payment were assumed to increase by 1.238% per year and by 1.125% per year in respect of Contributory and Non-Contributory/SME portions of the defined benefit component of the Plan, respectively.

Demographic Assumptions

Retirement Age

Because early retirement pensions are reduced in accordance with a formula, the retirement age of Plan members has an impact on the cost of the Plan.

We have assumed an age-related scale as follows for members who retire from active status from the Plan:

Annual Retirement Rates

Age	Percentage
55-56	5.0%
57-58	7.5%
59	10.0%
60-64	20.0%
65	100.0%

A 20% retirement rate is assumed in lieu of the above rate in the year in which a member qualifies for early retirement with an unreduced pension and in each subsequent year until age 65.

For members who terminate from the Plan before being eligible to retire we have assumed pension commencement at age 55.

Retirement rates are typically developed taking into account the past experience of the Plan. Accordingly, the rates of retirement have been developed as our expectation of the best estimate rates given past experience. Recent experience indicates this assumption remains appropriate.

Termination of Employment

We have made an allowance for projected benefits payable on the termination of employment before retirement for reasons other than death. Sample rates are shown in the following table:

Annual Retirement Rates

Age	Male	Female
25	5.0%	13.0%
30	5.0%	11.0%
35	4.6%	8.5%
40	3.0%	4.0%
45	2.5%	3.9%
50	1.5%	2.8%
55	0.0%	0.0%

For this valuation, we have assumed that two-thirds of terminating members will elect a commuted value determined on a basis consistent with the 2009 CIA standard.

Mortality

The actuarial value of the pension depends on the lifetime of the member.

The 1994 Uninsured Pension Mortality Table reflects the mortality experience as of 1994 for a large sample of North American pension plans. Applying projection scale AA provides an allowance for improvements in mortality after 1994. This table is commonly used for valuations where the membership of a plan is insufficient to assess plan specific experience and where there is no reason to expect the mortality to differ from that of other pension plans. Both are true for this plan.

While there is strong evidence of continuing improvement in mortality, forecasts of the rate of future improvement are very uncertain. We have used the projection scale AA to reflect future improvements in mortality.

We have assumed mortality rates, both before and after retirement, in accordance with the 1994 Uninsured Pension Mortality Table with projection scale AA applied to reflect continuing future improvements in mortality (i.e. generational improvements). According to this table, the life expectancy at age 65, as of the valuation date, is 19.4 years for a man and 22.0 years for a woman.

Disability

No allowance has been made for disability on the basis that the impact of including such an assumption would not have a material impact on the valuation results. We have assumed that those currently disabled would remain disabled until retirement and would to continue to accrue benefits until retirement in accordance with Plan terms.

Family Composition

Benefits in case of death, before and after retirement, depend on the Plan member's marital status.

We have assumed that 80% of Plan members will have an opposite-sex spouse on the earlier of death or retirement, and that the male partner will be two years older than the female partner.

Defined Benefit / Defined Contribution Choice

The current service cost depends on the members' participation in the defined benefit or defined contribution components of the Plan. We have assumed that members will continue to accrue benefits in the component they are participating in at the valuation date.

Defined Benefit Actuarial Valuation Methods and Assumptions – Solvency and Impact of Plan Wind-up

We have used the market value of the Plan's assets in our valuation of the Plan for solvency purposes.

To determine the solvency actuarial liability, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with the exception of certain benefits which may be excluded, as permitted by the *Pension Benefits Act (Ontario)*. Specifically, future increases on pensions in payment were excluded from our calculations of solvency liabilities. All members are assumed to be fully vested in their accrued benefits. The circumstances in which the Plan wind-up is assumed to have taken place are as follows:

- Membership in the Plan ceases on the valuation date, and
- No projection of salaries and YMPE are assumed to occur after the valuation date for active and suspended members.

Thereby giving rise to the following benefits:

- Active and suspended members not within 10 years of pensionable age (under the age of 55) receive the termination benefit under the Plan,
- Active and suspended members within 10 years of pensionable age (age 55 and older) receive the retirement benefit under the Plan, and
- Deferred pensioners, pensioners and survivors receive the benefit to which they are entitled on the valuation date.

We have considered that members under 55 years of age on that date would be entitled to a deferred pension payable from age 55. Members aged 55 and over are considered to be entitled to an immediate pension, reduced in accordance with the Plan rules.

Benefits are assumed to be settled through a lump sum transfer for members under 55 years of age. The value of the benefits accrued on December 31, 2008 for such members is based on the assumptions described in *Section 3800 – Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice (CIA Standard) applicable for December 31, 2008 for benefits expected to be settled through transfer in accordance with relevant portability requirements. The liabilities for these members were calculated using the April 1, 2009 CIA Standard.

Benefits are assumed to be settled through the purchase of annuities for members aged 55 and over. The value of the benefits accrued on December 31, 2008, for such members are based on an estimate of the cost of settlement through purchase of annuities.

However, there is limited data available to provide credible guidance on the cost of purchasing indexed annuities in Canada. Therefore, we have relied on the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuation with Effective Dates Between December 31, 2008 and December 30, 2009.*

Assumptions are as follows:

Actuarial Assumptions

For benefits to be settled through a lump sum transfer	
Interest rate:	4.20% per year for 10 years following December 31, 2008, and 5.70% per year thereafter
Mortality rates:	UP-1994 projected to 2020
Post-retirement indexing[5]:	0.00% per year
Maximum pension limit:	Projected to age 55 ($2,444.44 per year of service in 2009, increased thereafter at 2.34% for 10 years, 2.95% thereafter)
For benefits to be settled through the purchase of an annuity	
Interest rates:	4.85% per year
Mortality rates:	UP-1994 projected to 2015
Post-retirement indexing:	▪ 1.48% per year for benefits in respect of Contributory service ▪ 1.35% per year for benefits in respect of Non-Contributory and SME service
Maximum pension limit:	$2,444.44 per year of service
For all benefits	
Interest rate used to determine the present value of special payments:	4.68%
Final average earnings:	Based on actual pensionable earnings and bonuses over the averaging period
Family composition:	Same as for going-concern valuation
Termination expenses:	$600,000

We have assumed that benefits of active and suspended members whose age plus service is at least 55, pensioners, and survivors would be indexed. We have assumed that the benefits of active and suspended members whose age plus service is less than 55 and deferred pensioners would not be indexed.

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[5] For indexed benefits assumed to be settled through a lump sum transfer, post-retirement indexing is assumed to be as follows:

- 0.740% per year for 10 years following December 31, 2008, and 1.073% per year thereafter, in respect of Contributory service, and,
- 0.672% per year for 10 years following December 31, 2008, and 0.976% per year thereafter, in respect of Non-Contributory and SME service.

In a solvency valuation, the accrued benefits are based on the member's final average earnings on the valuation date; therefore no salary projection is used. Also, the employment of each member is assumed to have terminated on the valuation date; therefore, no assumption is required for future rates of termination of employment.

To determine both the solvency and hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administrative expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

In determining the estimated termination expenses, we have assumed that the Plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred in actual Plan wind-up may differ materially from the estimates disclosed in this report.

Appendix C

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2008, provided by Enbridge Gas Distribution Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, sex, etc.), pensionable earnings levels, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Lump sum payments and pensions to retirees were compared with corresponding amounts reported in the financial statements. The results of these tests were satisfactory.

Plan membership data is summarized below. For comparison, we have also summarized corresponding data from the previous valuation at December 31, 2007.

Membership Data*

	12.31.2008	12.31.2007
Active and Disabled Members Accruing Defined Benefit Service (Non- Senior Manager Employees)		
Number	1,753	1,770
Total base pensionable earnings at the valuation date	$121,401,000	$119,172,000
Average base pensionable earnings at the valuation date	$69,300	$67,300
Average years of non-SME DB pensionable service	13.8 years	13.6 years
Average age	46.1 years	45.9 years
Active and Disabled Members Accruing Defined Benefit Service (Senior Manager Employees)		
Number	33	31
Total base earnings at the valuation date	$5,954,000	$5,488,000
Average base earnings at the valuation date	$180,400	$177,000
Total base pensionable earnings at the valuation date	$4,033,000	$3,617,000
Average base pensionable earnings at the valuation date	$122,200	$116,700
Average years of non-SME DB pensionable service	12.2 years	13.1 years
Average years of SME DB pensionable service	0.9 years	0.0 years
Average age	48.9 years	48.6 years
Suspended Defined Benefit Members Accruing Defined Contribution Service		
Number	108	127
Total base pensionable earnings at the valuation date	$8,710,000	$9,909,000
Average base pensionable earnings at the valuation date	$80,600	$78,000
Average years of non-SME DB pensionable service	5.6 years	5.7 years
Average years of continuous service	15.2 years	14.6 years
Average age	42.9 years	42.3 years
Other Suspended Defined Benefit Members		
Number	20	19
Total base pensionable earnings at the valuation date	$4,248,000	$3,481,000
Average base pensionable earnings at the valuation date	$212,400	$183,200
Average years of non-SME DB pensionable service	6.7 years	8.3 years
Average age	46.5 years	48.5 years

* Base earnings and pensionable earnings exclude bonuses for the purpose of this table.

Membership Data* (cont'd)

	12.31.2008	12.31.2007
Active Defined Contribution Members without Defined Benefit Service		
Number	212	215
Total base pensionable earnings at the valuation date	$15,809,000	$15,683,000
Average base pensionable earnings at the valuation date	$74,600	$72,900
Average years of continuous service	4.3 years	3.5 years
Average age	39.6 years	37.4 years
Suspended Defined Contribution Members without Defined Benefit Service		
Number	7	5
Total base pensionable earnings at the valuation date	$706,000	$505,000
Average base pensionable earnings at the valuation date	$100,900	$101,000
Average years of continuous service	6.7 years	6.5 years
Average age	33.3 years	48.7 years
Deferred Pensioners		
Number	177	169
Total annual deferred pension	$862,700	$860,000
Average annual deferred pension	$4,900	$5,100
Accumulated excess DB contributions with interest	$637,000	$594,000
Average age	49.3 years	48.7 years
Pensioners and Survivors		
Number	1,334	1,297
Total annual lifetime pension	$24,925,000	$23,242,000
Average annual lifetime pension	$18,700	$17,900
Total annual temporary pension	$1,511,000	$2,217,000
Average age	72.0 years	71.8 years

* Base earnings and pensionable earnings exclude bonuses for the purpose of this table.

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

Reconciliation of Membership

	Active and Disabled Members Accruing DB Service	**Suspended DB Members**	**Active DC Members (without DB service)**	**Deferred Pensioners**	**Pensioners and Survivors**	**Total**
Number at December 31, 2007	**1,801**	**146**	**220**	**169**	**1,297**	**3,633**
Adjustments	-	-	-	3	-	3
New entrants	79	-	28	-	-	107
Transfers						
▪ Transfer from DC to DB	20	(15)	(5)	-	-	-
▪ Transfer from DB to DC	(2)	2	-	-	-	-
▪ Transfer from DC to SME	3	-	(3)	-	-	-
▪ SME transfer from West to East	1	(1)	-	-	-	-
▪ SME transfer from East to West	(4)	4	-	-	-	-
▪ Net to suspended status	-	-	-	-	-	-
Retirements						
▪ DB retirements	(59)	(3)	-	(3)	65	-
▪ DC retirements	-	-	(2)	-	-	(2)
Terminations of employment						
▪ Refunds & lump sum payments	(25)	(2)	(13)	(8)	-	(48)
▪ Deferred pensions	(11)	(3)	-	16	-	2
▪ Non-vested terminations	(12)	-	(6)	-	-	(18)
▪ Terminations not yet elected	(2)	-	-	-	-	(2)
Deaths						
▪ With further entitlement	(2)	-	-	-	(16)	(18)
▪ Without further entitlement	(1)	-	-	-	(30)	(31)
▪ New survivors	-	-	-	-	18	18
Number at December 31, 2008	**1,786**	**128***	**219****	**177**	**1,334**	**3,644**

* Of these 128 members, 108 are currently accruing benefits in the DC component of the Plan.

** Of these 219 members, 212 are currently accruing benefits in the DC component of the Plan.

The distribution of active and disabled members, by age and service as at December 31, 2008 is summarized as follows:

Distribution of Active and Disabled Non-SME DB Members Pensionable Earnings by Age Group and DB Pensionable Service

	Years of Defined Benefit Pensionable Service as at December 31, 2008								
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35 +**	**TOTAL**
Under 20									
20 – 24	21								21
	$50,410								$50,410
25 – 29	139	2							141
	$58,883	*							$59,106
30 - 34	114	14	2						130
	$59,892	$66,759	*						$60,805
35 - 39	104	32	24	3					163
	$63,932	$76,427	$75,178	$67,830					$68,133
40 - 44	112	26	33	67	10				248
	$66,370	$79,830	$80,544	$69,953	$67,704				$70,689
45 – 49	79	32	33	70	74				288
	$68,629	$68,794	$67,543	$70,693	$73,967				$70,396
50 - 54	45	29	26	44	49	150			343
	$66,124	$82,405	$68,415	$71,570	$74,310	$76,224			$73,959
55 - 59	24	10	16	30	22	87	96		285
	$65,534	$80,400	$66,193	$69,379	$78,008	$73,297	$74,240		$72,762
60 - 64	9	6	11	22	12	19	31	13	123
	$54,925	$88,586	$70,832	$68,107	$63,850	$64,052	$66,479	$75,322	$67,696
65 +		1	1	2	1	2	2	2	11
		*	*	*	*	*	*	*	$69,541
TOTAL	**647**	**152**	**146**	**238**	**168**	**258**	**129**	**15**	**1,753**
	$62,779	**$76,427**	**$71,951**	**$70,359**	**$73,439**	**$74,246**	**$72,280**	**$73,269**	**$69,253**

Total base pensionable earnings: $121,401,400

Average age: 46.1 years

Average years of DB pensionable service: 13.8 years

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Distribution of Active and Disabled SME Members Pensionable Earnings by Age Group and DB Pensionable Service

	Years of Non-SME Defined Benefit Pensionable Service as at December 31, 2008								
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35 +**	**TOTAL**
Under 35									
35 - 39	2	1							3
	*	*							$157,706
40 - 44	3	2		1					6
	$166,270	*		*					$161,746
45 – 49	2	1	1	2	1				7
	*	*	*	*	*				$185,138
50 - 54	3	4		3	1	1			12
	$186,219	$203,390		$171,268	*	*			$182,769
55 - 59	1		1	1					3
	*		*	*					$222,329
60 - 64			1	1					2
			*	*					$177,165
65 +									
TOTAL	**11**	**8**	**3**	**8**	**2**	**1**			**33**
	$168,364	**$186,055**	**$229,099**	**$181,517**	**$162,712**	**$148,806**			**$180,427**

Total base earnings: $5,954,100

Average age: 48.9 years

Average years of DB pensionable service: 9.8 years

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Distribution of Active and Disabled DC Members Pensionable Earnings by Age Group and Continuous Service

	Years of Continuous Service as at December 31, 2008								
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35 +**	**TOTAL**
Under 20									
20 – 24	5								5
	$53,959								$53,959
25 – 29	34	5							39
	$63,955	$63,568							$63,905
30 - 34	22	11	3						36
	$63,756	$78,237	$81,948						$69,697
35 - 39	30	10	21	9					70
	$75,834	$88,949	$79,035	$83,075					$79,599
40 - 44	16	13	10	20	2				61
	$76,667	$89,681	$90,322	$75,673	*				$81,279
45 – 49	19	12	11	11	7	2			62
	$76,985	$91,032	$86,012	$70,248	$82,016	*			$80,310
50 - 54	11	5	5	5	1				27
	$71,096	$68,496	$100,767	$76,693	*				$76,981
55 - 59	2	2	2						6
	*	*	*						$104,466
60 - 64	5	3							8
	$80,030	$71,751							$76,925
65 +	5	1							6
	$72,017	*							$70,144
TOTAL	**149**	**62**	**52**	**45**	**10**	**2**			**320**
	$70,804	**$83,021**	**$86,282**	**$75,941**	**$78,960**	**$65,565**			**$76,631**

Total base earnings: $24,521,600

Average age: 40.7 years

Average years of continuous service: 7.5 years

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Distribution of Inactive Members by Age Group

	Deferred Pensioners		Pensioners and Survivors	
Age	**Number**	**Average Annual Pension**	**Number**	**Average Annual Pension**
25 - 29	1	*		
30 - 34	12	$761		
35 - 39	20	$2,482	1	*
40 - 44	31	$3,303	1	*
45 - 49	39	$6,634	1	*
50 - 54	31	$6,081	3	$4,492
55 - 59	24	$4,986	105	$22,741
60 - 64	11	$11,700	211	$23,153
65 - 69			270	$21,585
70 - 74			244	$20,002
75 - 79	2	*	239	$14,844
80 - 84			149	$14,622
85 - 89	6	$436	84	$11,415
90 - 94			19	$9,387
95 +			7	$8,304
Total	**177**	**$4,874**	**1,334**	**$18,685**

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Appendix D

Summary of Plan Provisions

Introduction

The effective date of the Plan is January 1, 1971.

Effective July 1, 2001, the Plan was redesigned for all members active or suspended at that date. Prior to the redesign, participants in the DB component of the Plan accrued Contributory DB credited service. Following the redesign, participants in the DB component of the Plan accrue Non-Contributory DB credited service.

Effective January 1, 2008, Senior Management Employees (SMEs) employed by Enbridge Gas Distribution Inc., Enbridge Gas New Brunswick Inc., Enbridge Electric Connections Inc., Enbridge Solutions Inc., and Gazifere Inc. ceased accruing benefits under the Retirement Plan for the Employees of Enbridge Inc. and Affiliates and began accruing benefits under the Plan.

The provisions of the Plan as they existed on December 31, 2008 are summarized as follows, subject to the *Income Tax Act* maximums:

DB Component

	Plan Provisions
Eligibility	Immediate eligibility
Vesting	24 months of continuous service (immediate if SME member)
Employee Contributions	Not permitted.
Normal Retirement Date	Age 65.
Early Retirement Date	Age 55.
Unreduced Early Retirement Date	Age 55 and 30 years of continuous service, or age 60.
Final Three Average Earnings	Best 3 years in the last 10 including 50% of eligible bonuses.
Final Five Average Earnings	Best 5 years in the last 10 including 50% of eligible bonuses.
Eligible Bonuses	
Final Three Average Earnings	Annual bonuses paid after June 30, 2001.
Final Five Average Earnings	Senior executive bonuses only.

Lifetime Benefits	
Normal Retirement	2.0% of final three average earnings multiplied by SME credited service Plus 1.2% of final three average earnings multiplied by Non-Contributory DB credited service, minus 50% of Non-Contributory C/QPP entitlement. Plus 2% of final five average earnings multiplied by Contributory DB credited service, minus 100% of Contributory C/QPP entitlement.
Early Retirement	Above pension if unreduced early retirement date has been reached, otherwise reduced by 5% per year for non-SME service, and 3% per year for SME service, for each year before age 60.
Bridge Benefits	50% of Non-Contributory C/QPP entitlement payable from the date of retirement to age 60, and reduced, unless unreduced early retirement date has been reached, by 5% per year before age 60. Plus 100% of Contributory C/QPP entitlement payable from the date of retirement to age 65.

C/QPP Entitlement Definition

Non-Contributory	25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the 5 calendar years, including the current year, preceding the date of exit, reduced by 6% per year from age 65 to age at exit, to a maximum reduction of 30%. This amount is then divided by 85% of the period between the later of the member's 18th birthday and January 1, 1966 and the member's 65th birthday and multiplied by Non-Contributory DB credited service.
Contributory	One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the 5 calendar years, including the current year, preceding the date of exit, multiplied by Contributory DB credited service, to a maximum of 35 years.
Normal Form of Payment	Joint and 60% survivor pension if the member has a spouse, and a life pension guaranteed for 15 years if the member is single.

Cost of Living Increases to Retiring Members	50% of annual increase in the CPI for Non-Contributory and SME benefits accrued 55% of annual increase in the CPI for Contributory benefits to a maximum of 5%. Increases are granted each December 1 after the first anniversary of retirement from active status.
Survivor Benefits	
Death After Retirement	Depends on the elected form of pension payment.
Death Before Retirement	If the member dies prior to retirement, the beneficiary is entitled to the value of the member's pension deferred, if applicable, to age 55 with a corresponding early retirement reduction.
Termination Benefit	If a member terminates prior to attaining age 55, he is entitled to the value of his pension deferred to age 55 with a corresponding early retirement reduction. If a member terminates after attaining age 55 he is considered to have retired.
Disability Benefit	Continued accrual of credited service until retirement in accordance with the benefit formula applicable at the member's date of disability. Contributions are not required during a period of disability.
50% Cost Sharing	If a member retires, terminates or dies after completion of 2 years of membership and the aggregate of his required contributions made on and after January 1, 1987 together with interest exceeds 50% of the commuted value of the contributory pension benefit accrued and granted with respect to his service on and after January 1, 1987, the member, the member's spouse or beneficiary, as the case may be, will be entitled to the excess. Such an amount may be taken in the form of a lump sum cash refund or may be transferred into a registered retirement savings plan on a non-locked-in basis.

DC Component

The employer contribution to the defined contribution component of the Plan is calculated as follows, subject to the *Income Tax Act* maximums:

Employer Contributions to the DC Component*	Point (age + continuous service) Criteria
4.0% of pensionable DC earnings	For members with less than 40 points.
5.5% of pensionable DC earnings	For members with more than 40 points but less than 60
7.0% of pensionable DC earnings	For members with more than 60 points

* For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

Members are immediately eligible to participate in the DC component of the Plan, and are vested in their DC account balance after two years of continuous service.

Members participating in the DC component or accruing Non-Contributory service under the DB component of the Plan will have one opportunity to switch pension components during their career, depending on the number of points (age plus years of continuous service).

The choices are available on the following dates:

- January 1 immediately after reaching 40 points, or
- January 1 immediately after reaching 60 points if the member did not switch upon reaching 40 points.

Appendix E

Results by Participating Employer

As of January 1, 2007, the Plan's defined benefit component assets were partitioned for internal reporting purposes based on the going-concern liabilities in respect of active members, adjusted for a proportional share of surplus, for each participating employer. A corresponding partition in respect of inactive members was made as at December 31, 2007.

As of December 31, 2007 and at each subsequent valuation, assets are transferred between participating employers in respect of members that transfer between employers. The amount of assets transferred is equal to the amount of going-concern liabilities accrued by the member at the transfer date, adjusted by a proportional share of surplus.

This appendix summarizes the main results by participating employer, as if the required asset transfers have been completed as at the valuation date.

Financial Position on a Going-Concern Basis

The results of the valuation of the defined benefit component as at December 31, 2008 partitioned by participating employer and reflecting December 31, 2008 intraplan asset transfers, are summarized as follows:

Financial Position - Going-Concern Basis

	Market Value of Assets	Total Defined Benefit Liability	Funding Excess (Funding Shortfall)
Enbridge Gas Distribution Inc.	$608,680,000	$610,250,300	($1,570,300)
Enbridge Gas New Brunswick Inc.	$5,493,100	$5,773,200	($280,100)
Enbridge Electric Connections Inc.	$2,718,900	$2,886,000	($167,100)
Gazifere Inc.	$8,939,700	$9,109,900	($170,200)
Enbridge Solutions Inc.	$2,401,300	$2,547,200	($145,900)
Total	$628,233,000	$630,566,600	($2,333,600)

To determine assets for each employer, we have relied upon unaudited financial statements provided by CIBC Mellon with adjustments as required.

The defined benefit liability is allocated by employer based on membership data at the valuation date.

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members accruing defined benefit or defined contribution service during 2009 partitioned by participating employer is summarized below:

Employers' Current Service Cost

	Defined Benefit Component		Defined Contribution Component	
	Percentage of Base Pensionable Earnings	**Estimated Current Service Cost**	**Estimated Current Service Cost**	**Total**
Enbridge Gas Distribution Inc.	12.2%	$13,670,100	$1,221,900	$14,892,000
Enbridge Gas New Brunswick Inc.	9.3%	$522,500	$95,700	$618,200
Enbridge Electric Connections Inc.	10.9%	$218,600	$47,200	$265,800
Gazifere Inc.	9.9%	$319,800	$38,600	$358,400
Enbridge Solutions Inc.	11.3%	$117,700	$26,900	$144,600
Total	12.0%	$14,848,700	$1,430,300	$16,279,000

Membership Data by Participating Employer

The membership data for members as at December 31, 2008 partitioned by participating employer is summarized below:

Active and Disabled Non-SME Members Accruing Defined Benefit Service

	Number	Average Age	Average Non-SME DB Pensionable Service	Total Pensionable Earnings	Average Pensionable Earnings
Enbridge Gas Distribution Inc.	1,566	46.9	14.8	$110,135,000	$70,300
Enbridge Gas New Brunswick Inc.	101	38.7	3.3	$5,502,000	$54,500
Enbridge Electric Connections Inc.	22	37.7	5.4	$1,888,000	$85,800
Gazifere Inc.	55	40.2	9.4	$3,218,000	$58,500
Enbridge Solutions Inc.	9	41.2	5.3	$658,000	$73,100
Total	1,753	46.1	13.8	$121,401,000	$69,300

Active and Disabled SME Members Accruing Defined Benefit Service

	Number	Average Age	Average Non-SME DB Pensionable Service	Total Pensionable Earnings	Average Pensionable Earnings
Enbridge Gas Distribution Inc.	29	48.0	12.0	$5,242,000	$180,800
Enbridge Gas New Brunswick Inc.	1	*	*	*	*
Enbridge Electric Connections Inc.	1	*	*	*	*
Gazifere Inc.	0	-	-	-	-
Enbridge Solutions Inc.	2	*	*	*	*
Total	33	48.9	12.2	$5,954,000	$180,400

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Suspended Defined Benefit Members Accruing Defined Contribution Service

	Number	Average Age	Average Non-SME DB Pensionable Service	Total Pensionable Earnings	Average Pensionable Earnings
Enbridge Gas Distribution Inc.	102	42.8	5.4	$8,233,000	$80,700
Enbridge Gas New Brunswick Inc.	2	*	*	*	*
Enbridge Electric Connections Inc.	1	*	*	*	*
Gazifere Inc.	3	41.7	9.0	$192,000	$64,000
Enbridge Solutions Inc.	0	-	-	-	-
Total	108	42.9	5.6	$8,710,000	$80,600

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Other Suspended Defined Benefit Members Accruing Defined Contribution Service

	Number	Average Age	Average Non-SME DB Pensionable Service	Total Pensionable Earnings	Average Pensionable Earnings
Enbridge Gas Distribution Inc.	18	46.5	6.2	$3,827,000	$212,600
Enbridge Gas New Brunswick Inc.	0	-	-	-	-
Enbridge Electric Connections Inc.	0	-	-	-	-
Gazifere Inc.	0	-	-	-	-
Enbridge Solutions Inc.	2	*	*	*	*
Total	20	46.5	6.7	$4,248,000	$212,400

Defined Contribution Members Without Defined Benefit Service

	Number	Average Age	Average Continuos Service	Total Pensionable Earnings	Average Pensionable Earnings
Enbridge Gas Distribution Inc.	164	39.2	4.5	$12,639,000	$77,100
Enbridge Gas New Brunswick Inc.	28	41.0	3.1	$1,609,000	$57,500
Enbridge Electric Connections Inc.	6	49.0	3.3	$591,000	$98,500
Gazifere Inc.	9	38.1	4.6	$479,000	$53,200
Enbridge Solutions Inc.	5	37.9	3.6	$491,000	$98,200
Total	212	39.6	4.3	$15,809,000	$74,600

Deferred Pensioners

	Number	Average Age	Total Annual Pension	Average Annual Pension
Enbridge Gas Distribution Inc.	165	49.7	$794,400	$4,800
Enbridge Gas New Brunswick Inc.	4	43.6	$23,900	$6,000
Enbridge Electric Connections Inc.	1	*	*	*
Gazifere Inc.	5	39.6	$8,100	$1,600
Enbridge Solutions Inc.	2	*	*	*
Total	177	49.3	$862,700	$4,900

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Pensioners and Survivors

	Number	Average Age	Total Annual Pension	Average Annual Pension
Enbridge Gas Distribution Inc.	1,310	72.1	$24,500,000	$18,700
Enbridge Gas New Brunswick Inc.	7	57.9	$160,000	$22,900
Enbridge Electric Connections Inc.	0	-	-	-
Gazifere Inc.	16	67.9	$264,000	$16,500
Enbridge Solutions Inc.	1	*	*	*
Total	1,334	72.0	$24,925,000	$18,700

* Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

Appendix F

Employer Certification

With respect to the report on the actuarial valuation of the *Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates* (the "Plan"), for funding purposes as at December 31, 2008, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official Plan documents and all amendments made up to December 31, 2008, were provided to the actuary;
- the membership data provided to the actuary includes a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2008, and
- all events subsequent to December 31, 2008 that may have an impact on the results of the valuation have been communicated to the actuary.

11-27-2009

Date

Signed

RON. L. SAWATZKY.

Name

MERCER

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APPRO INTERROGATORY #2

INTERROGATORY

Exhibit C Tab 1 Schedule 4, Updated 2010-01-22; refers to Bill 218 which introduced certain tax changes by the Ontario Government. The income and capital tax changes effects have been reflected in the updated evidence as provided for in the Settlement Agreement. Bill 218 also deals with harmonization of the provincial sales tax with the federal goods and services tax effective July 1, 2010. It is understood that those goods and services purchased by the company for the period after July 1, 2010, that had previously attracted a provincial sales tax, will receive an input tax credit under the HST rules.

a. Please identify the expected magnitude of the provincial sales tax portion of the HST related to the goods and services that will be purchased after July 1, 2010.
b. Please explain why Enbridge has not also reduced the revenue requirement by 50% of the input tax credit that will be received for the provincial sales tax portion of the HST as provided for in the Settlement Agreement.

RESPONSE

Please see the responses to Board Staff Interrogatory #14 at Exhibit I, Tab 1, Schedule 14, BOMA Interrogatory #10 at Exhibit I, Tab 3, Schedule 10 and SEC Interrogatory #9 at Exhibit I, Tab 6, Schedule 9.

EGD has not reflected any impact of a change in a PST/HST related element within the 2010 revenue requirement. The reason is that in order to quantify the impact of the change it would be necessary to compare the entire impact of the change in a detailed fashion to the former Provincial Sales Tax related impacts which were inherent within 2007 base rates used within the EGD IR methodology. Please refer to the response to BOMA Interrogatory #10 filed at Exhibit I, Tab 3, Schedule 10.

Witness: K. Culbert

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Ex. B, Tab 1, Sch. 2, Appendix A

a) What would be the impact on the gross return component of 9.36% shown in page 3 of Appendix A if the corporate income tax rate of 31% was used in the calculation?

b) What is the impact on the carrying cost requirement of $36,740.4 shown in page 1 of Appendix A if the gross return component using a corporate tax rate of 31% was used for 2010?

c) Please explain why ratepayers are not entitled to the reduction in the carrying cost requirement calculated above.

RESPONSE

The carrying cost on gas in storage for 2010 continues to use the 2007 Board Approved gross return component of 9.36% just as was used for the 2008 and 2009 Board Approved carrying cost of gas in storage.

Each of the approved QRAM applications throughout 2008, 2009, and 2010 indicated the continued use of the 2007 Board Approved gross return component where increases and decreases in carrying costs relative to forecast changes in natural gas prices were determined using the 2007 Approved gross return.

As was indicated within each of the QRAM applications, the 2007 Board Approved gross return calculation continues to be used for 2008 to 2012 as the impacts of forecast tax rate changes for these years and any variances from forecast tax rate changes are handled in compliance with the Board Approved 2008 Incentive Regulation – Settlement Proposal, Appendix D.

Changes in tax rates are handled within the Tax Rate and Rule Change Variance Account agreement (“TRRCVA”).

Witnesses: K. Culbert
T. Ladanyi

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Ex. B, Tab 1, Sch. 4, Table 2

a) Please add a column to Table 2 to show the 2008 Board approved budget in the same level of detail as shown in the table.

b) Please provide, in the same level of detail as shown in Table 2, the actual customer additions for 2007 and the corresponding Board approved forecast additions from the 2007 rates proceeding.

c) Please provide, in the same level of detail as shown in Table 2, the actual 2009 (or if unavailable, the estimate based on the most recent year-to-date) customer additions.

d) What would be the impact on the revenue requirement and the proposed rate increase if the 2010 forecast of customer additions was reduced by 10% across all sectors?

RESPONSE

a) Please see Table 2 on the following page.

Witnesses: J. Denomy
S. Murray

Table 2
Customer Additions with 2008 Board Approved Budget

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Sector	2008 Actual	2009 Board Approved Budget	2010 Forecast	2008 Board Approved Budget
Residential				
New Construction	30,300	31,739	22,616	33,897
Replacement	7,742	6,548	7,174	7,092
Total	38,042	38,287	29,790	40,989
Apartment				
New Construction	22	41	19	43
Replacement	6	7	7	17
Total	28	48	26	60
Commercial				
New Construction	2,019	1,955	1,665	2,381
Replacement	957	941	888	1,086
Total	2,976	2,896	2,553	3,467
Industrial				
New Construction	5	8	7	13
Replacement	1	2	3	5
Total	6	10	10	18
Total Customer Additions	41,052	41,241	32,379	44,534

b)

2007 Customer Additions Summary

Col. 1	*Col. 2*	*Col. 3*
Sector	2007 Actual	2007 Board Approved Budget
Residential		
New Construction	32,900	35,098
Replacement	7,008	8,518
Total	39,908	43,616
Apartment		
New Construction	5	42
Replacement	5	16
Total	10	58
Commercial		
New Construction	1,943	1,599
Replacement	1,050	932
Total	2,993	2,531
Industrial		
New Construction	6	16
Replacement	3	7
Total	9	23
Total Customer Additions	42,920	46,228

c)

2009 Customer Addition Actuals

Col. 1	*Col. 2*
Sector	2009 Actual
Residential	
New Construction	23,110
Replacement	6,385
Total	29,495
Apartment	
New Construction	66
Replacement	2
Total	68
Commercial	
New Construction	1,899
Replacement	621
Total	2,520
Industrial	
New Construction	5
Replacement	1
Total	6
Total Customer Additions	32,089

d) See Exhibit I, Tab 5, Schedule 1, CME Interrogatory #1(b).

Witnesses: J. Denomy
S. Murray

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Ex. B, Tab 1, Sch. 5, page 1

a) Please explain what is meant by the statement that "The 2010 forecast of gas volumes incorporates calendar 2008 actual billing consumption". Does this mean that the regression analysis uses actual data through to the end of calendar 2008?

b) Have the 2008 actual and 2009 bridge year estimates of volumes been normalized based on the number of degrees days used in the 2008 and 2009 Board approved budgets? If not, please revise Table 1 to provide the 2008 actual and 2009 bridge year estimate based on the number of degree days used in the approved budgets for each of 2008 and 2009.

RESPONSE

a) The statement that 2010 forecast of gas volumes incorporates calendar 2008 actual billing consumption means that 2008 full year actual volumes were incorporated as inputs to both General Service (i.e., regression models) and Large Volume budgets.

b) Consistent with previous filings, the 2008 actual represents actual billing data based on 2008 actual billing or meter reading heating degree days. Similarly, both the 2009 Bridge Year Estimate and 2009 Board Approved Budget volumes were based on the 2009 Board Approved Budget degree days. Table 1 illustrates the recasted 2008 Actual volumes after weather normalization adjustments have been made to the 2008 Actuals utilizing the 2008 Board Approved Budget degree days as stated in EB-2009-0055, Exhibit B, Tab 3, Schedule 2, page 2, Column 4.

Witnesses: I. Chan
T. Ladanyi

Table 1
Summary of Gas Sales and Transportation
Volumes and Customers – Year 2008
(Volumes in $10^6 m^3$)

	2008 Board Approved Budget	2008 Actual	2008 Normalized Actual	
General Service Volumes	8 288.0	8 806.0	8 369.7	
Contract Volumes	3 555.2	3 101.5	3 099.6	
Total Volumes, Gas Sales and Transportation	11 643.2	11 907.5	11 469.3	
Customers, Gas Sales and Transportation (Average)	1 864 047	1 865 020	1 865 020	/c

Witnesses: I. Chan
T. Ladanyi

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Ex. B, Tab 1, Sch. 5

a) How many months of actual consumption are included in the 2009 bridge year estimate?

b) Please update tables 1 and 2 & figures 1 and 2 to show the 2009 bridge year estimate based on the most recent year-to-date actual information available.

c) Have all of the years shown in figures 1 and 2 been normalized to the same number of degree days? If yes, have they been normalized to the 2010 forecast of degree days? If not, please explain what they have been normalized to.

RESPONSE

a) As stated in Exhibit B, Tab 1, Schedule 5, page 25, the 2009 Bridge Year Estimate for contract market customers has incorporated three months of 2009 actual information. As average use regression models are on an annualized basis, the regression models forecast includes 2008 actual billing consumption information up to and including December 2008 (p. 7 of Exhibit B, Tab 1, Schedule 5). Page 1 of Exhibit B, Tab 1, Schedule 5, Appendix B illustrates that the 2009 Bridge Year Estimate customer additions have incorporated four months actual. Overall, both 2009 Bridge Year Estimate and 2010 Budget represent the forecasts that integrate all the actual experience and the best known information at the time of the development of the budget.

b) The following two pages present updated Tables 1 and 2 as well as Figures 1 and 2 with 2009 Actual information. The increase in volumes between 2009 Actual and 2009 Board Approved Budget as illustrated in Table 1 was primarily attributable to the favourable degree day variances. On a weather-normalized basis, the 2009 Actual volumes of 11 025.1 10^6m^3 were 374.7 10^6m^3 or 3.3% below 2009 Board Approved of 11 399.8 10^6m^3 as presented in the response to Board Staff Interrogatory #2 at Exhibit I, Tab 1, Schedule 2, Table 2. The decrease on a normalized basis is primarily due to unfavourable general service customer growth and average use as well as contract market customers' plant closures and production shutdown.

Witnesses: I. Chan
T. Ladanyi

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

	2008 Board Approved Budget	2008 Actual	2009 Board Approved Budget	2009 Actual	2010 Budget
General Service Volumes	8 288.0	8 806.0	9 083.2	9 129.2	9 083.5
Contract Volumes	3 555.2	3 101.5	2 316.6	2 205.6	2 008.6
Total Volumes, Gas Sales and Transportation	11 643.2	11 907.5	11 399.8	11 334.8	11 092.1
Customers, Gas Sales and Transportation (Average)	1 864 047	1 865 020	1 906 437	1 887 605	1 931 528
Meter Reading Degree Days (18ºC)	3 543	3 750	3 514	3 764	3 546

A one-month service delay of one power generation customer caused a slight reduction in contract demand volumes between 2009 Actual and Budget in Table 2 below.

Table 2
Summary of Unbundled Customers Contract Demand Volumes
(Volumes in 10^6m^3)

	2007 Board Approved Budget	2007 Actual	2008 Board Approved Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget
Total Contract Demand Volumes	14.6	12.5	38.1	40.0	74.2	73.3	82.6

c) Consistent with previous filings, both Figures 1 and 2 have been normalized to the current Test Year Budget degree days, i.e., 2010 forecast of degree days.

Witnesses: I. Chan
T. Ladanyi

Figure 1
Residential Normalized Average Use (m^3)

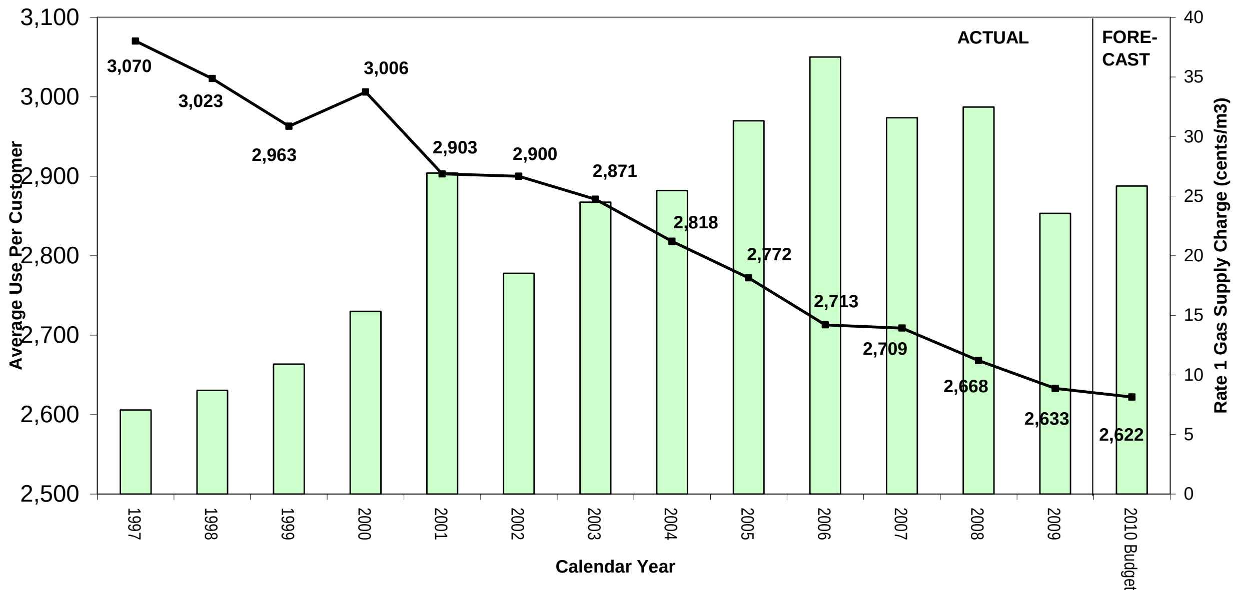
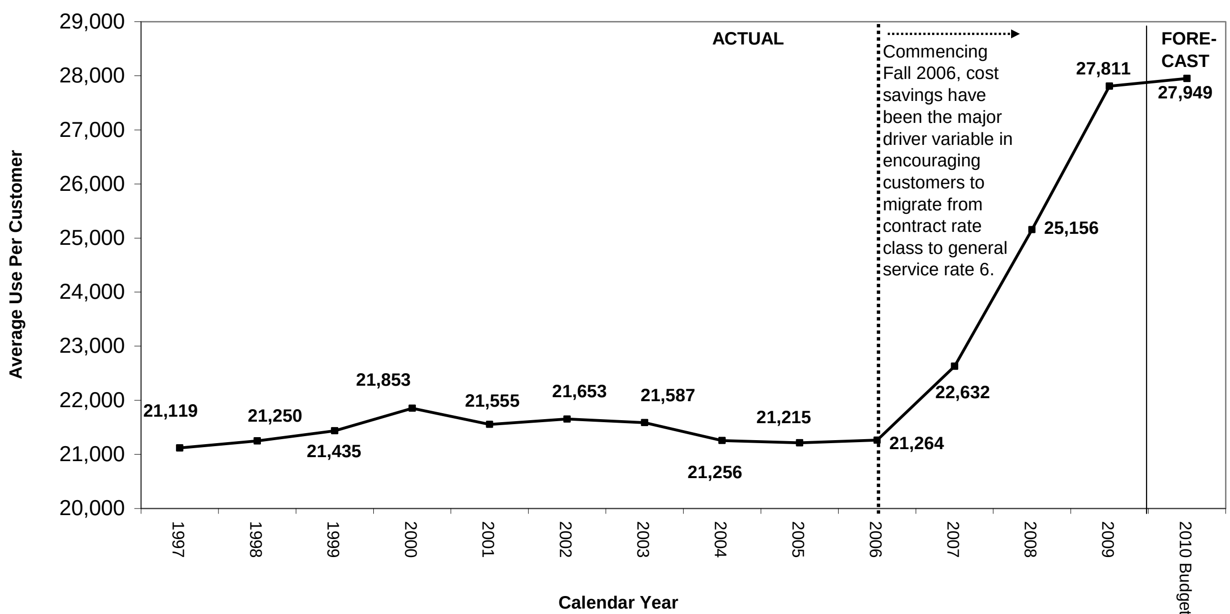


Figure 2
Rate 6 Normalized Average Use (m^3)



Witnesses: I. Chan
T. Ladanyi

BOMA INTERROGATORY #5

INTERROGATORY

Ref: Ex. B, Tab 1, Sch. 2, page 1 & Ex. B, Tab 2, Sch. 1, Appendix A, page 1

Please reconcile the 2009 figures related to the power generation projects of $3.2 shown at line 7 of Exhibit B, Tab 1, Schedule 2, page 1 and the figure of $3,088.8 (different units) in the 2009 column of Exhibit B, Tab 2, Schedule 1, Appendix A, page 1. Is the difference due only to rounding? If not, what is the difference between these figures related to?

RESPONSE

The $3.2 million, shown at Line 7 of Exhibit B, Tab 1, Schedule 2, page 1, was the 2009 forecast revenue requirement amount using information available at the time of the 2009 application, filed on September 26, 2008 (see EB-2008-0219, Exhibit B, Tab 1, Schedule 6, Appendix A, page 1).

The 3,088.8 ($000's) revenue requirement shown in Exhibit B, Tab 2, Schedule 1, Appendix A, pages 1 and 5, was updated to reflect the Company's latest forecast information for the 2009 calendar year.

Witnesses: I. Chan
K. Culbert
A. Kacicnik
T. Ladanyi
D. Small

BOMA INTERROGATORY #6

INTERROGATORY

Ref: Ex. B, Tab 2, Sch. 1, Appendix A

Please provide a capital cost continuity schedule showing the derivation of the CCA amounts show on page 4 of Appendix A for 2008, 2009 and 2010.

RESPONSE

The following CCA continuity schedule contains the calculation of CCA amounts (Column 8) included in Exhibit B, Tab 2, Schedule 1, Appendix A, updated 2010-01-22.

POWER GENERATION PROJECTS
CAPITAL COST ALLOWANCE CONTINUITY SCHEDULE

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
Year	C.C.A. Class	Opening U.C.C. Balances	Current year additions1	Rate	Current year C.C.A. with 1/2 year Rule	C.C.A. on opening balances	Total Eligible C.C.A.	Ending Eligible U.C.C.
		($000's)	($000's)		($000's)	($000's)	($000's)	($000's)
2008	51	-	14,432.2	6.00%	433.0	-	433.0	13,999.2
2009	51	13,999.2	6,470.0	6.00%	194.1	840.0	1,034.1	19,435.1
2010	51	19,435.1	475.0	6.00%	14.3	1,166.1	1,180.4	18,729.7

Note 1: Additions for CCA purposes does not include IDC which is handled through the regulatory capital structure.

Witnesses: K. Culbert
T. Ladanyi

BOMA INTERROGATORY #7

INTERROGATORY

Ref: Ex. B, Tab 2, Sch. 2

To which rate classes will EGD allocate the $1.25 million related to the proposed industrial support pilot program? How will EGD ensure that this increase in the revenue requirement is not allocated to other rate classes as part of the revenue per customer cap mechanism?

RESPONSE

The $1.25 million related to the industrial support program has been assigned through direct allocation to rate classes as shown in the table below. Only rate classes identified in the allocation have been assigned their portion of the $1.25 million.

Gas Rate	Industrial Sector Pilot Program
1	0%
6	0%
100	0%
110	18%
115	36%
135	2%
145	5%
170	39%
Grand Total	100%

The same information was provided in an interrogatory response to BOMA in EB-2009-0154 (Exhibit I, Tab 2, Schedule 4) and is replicated on the following page.

Witnesses: A. Mandyam
P. Squires
M. Suarez

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 1

a) How will EGD recover the $1.25 million budget proposed for 2010 pilot program proposal?

b) From which rate class/classes will these costs be recovered?

RESPONSE

a) Enbridge will recover the $1.25 million budget proposed for the 2010 pilot program from rates as a component of the Company DSM program.

b) The costs will be recovered as indicated in the table below.

Gas Rate	Industrial Sector Pilot Program
1	0%
6	0%
100	0%
110	18%
115	36%
135	2%
145	5%
170	39%
Grand Total	100%

Applicable customers in these rate classes will have access to the pilot program.

Witnesses: A. Mandyam
P. Squires
M. Suarez

BOMA INTERROGATORY #8

INTERROGATORY

Ref: Ex. B, Tab 3, Sch. 1, paragraph 29

a) Please explain why EGD is still requesting a Z factor adjustment of $18.9 million, based on the 2008 Mercer report, when the most recent estimate provided by Mercer is a total cost of $3.0 million.

b) Based on the most recent information available (i.e. beyond August 31, 2009), what is the current estimate from Mercer of the total cost to EGD?

RESPONSE

a) Only a formal year-end valuation can form the basis of determination of contributions. Interim estimates provide guidance, but do not qualify to form the basis of determination of such contributions. The Company acknowledges that the performance of financial markets in 2009 will likely result in the final contribution requirement being in the lower end of the contribution range of $3.0 million and $18.9 million noted in the evidence, however a final determination can only be made once the valuation report at December 31, 2009 becomes available.

b) The Company does not have a more recent estimate of the projected pension deficit, as at December 31, 2009. This is expected to be available no earlier than April, 2010.

Witnesses: J. Haberbusch
N. Kishinchandani

BOMA INTERROGATORY #9

INTERROGATORY

Ref: Ex. B, Tab 4, Sch. 1, Table 1 & Ex. A, Tab 2, Sch. 1

Please reconcile the T-service rate impacts shown in Table 1 that range from 0.6% to 1.70% with the 5.0% figures included in paragraph 10 of Exhibit A, Tab 2, Schedule 1.

RESPONSE

Exhibit A, Tab 2, Schedule 1 is the Application which Enbridge filed with the Ontario Energy Board (the Board) on September 2, 2009 and amended on September 14, 2009. The Application indicated an average increase in rates of approximately 5% or less for all customer classes on a T-service basis.

The filing of the Application enabled the Board to issue a Notice of Application ("NOA") and Enbridge to publish the NOA in local newspapers. This initiated the required public notice period. The indicated rate increase was derived in a conservative manner and was based on a set of assumptions.

As per its Incentive Regulation Settlement Agreement, the Company filed evidence on October 1, 2009 supporting the 2010 Rate Adjustment Application. The Company updated its evidence on January 22, 2010.

An example of an assumption that changed from September 2, 2009, when the Application was submitted, to October 1, 2009, when the evidence was filed is demand side management funding for low income energy consumers. The Company had considered a greater level of such spending in 2010 based on the recommendations of the working groups that formed part of the Board's low-income consultation process. After the Application was submitted, the Ontario Energy Board, as the result of instructions from the Minister of Energy and Infrastructure, directed utilities to refrain from introducing any new low-income programs pending the development of a province-wide program. As a result of this direction, Enbridge did not propose an increased level of low income spending as part of its 2010 Rate Adjustment.

Based on the updated evidence from January 22, 2010 average rate impacts are approximately 1.7% or less for all customer classes on a T-service basis.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

BOMA INTERROGATORY #10

INTERROGATORY

Ref: Ex. C, Tab 1, Sch. 4

The provincial government will convert the Ontario Retail Sales Tax (RST) to a value-added tax structure and combine it with the federal Goods and Services Tax (GST) to create a single harmonized sales tax (HST). This change will take place July 1, 2010.

Does EGD intend to calculate the impact of this change at the end of 2010 and bring forward any balance for disposal at that time as part of the sharing of tax change savings?

RESPONSE

As indicated in response to Board Staff Interrogatory #14 at Exhibit I, Tab 1, Schedule 14 and SEC Interrogatory #9 at Exhibit I, Tab 6, Schedule 9, EGD does not currently track Provincial sales tax separately within its actual or budgeted financials.

While EGD is in the process of analyzing the potential impacts of the sales tax change in terms of costs and or possible earnings impacts, the Company notes that there are many elements and issues to consider within such analysis. While attempting to create an estimate of the impact of the change is possible, the reality is that there may be no reasonable means of determining all impacts of the change with a high degree of certainty.

In order to quantify the impact of the PST/HST change, it would be necessary to compare the full HST impact of the change in a detailed fashion to the former Provincial Sales Tax (“PST”) impacts that were inherent within 2007 base rates.

PST related amounts and their impacts within rate base (gross and net), accounting income, and taxable income which had an impact within the established base for any Tax Rule and Rate Change comparative results and any comparison going forward cannot be derived as PST is not recorded separately by EGD either within budgeted or actual financials.

However, as requested in this interrogatory, Enbridge intends to analyze and determine an estimate of the impact of the change and bring forward the results, for review in conjunction with its 2011 IR rate application.

Witness: K. Culbert

CCC INTERROGATORY #1

INTERROGATORY

(B/T1/S4/p. 1) Please indicate to what extent, if any the methodology for determining the customer additions forecast for 2010 differs from that used to develop the 2009 forecast. To the extent there are any changes, please explain why those changes were made.

RESPONSE

No, the methodology for determining the 2010 customer additions forecast did not differ from the methodology used to determine 2009 customer additions.

Witnesses: J. Denomy
S. Murray

CCC INTERROGATORY #2

INTERROGATORY

(B/T1/S4/p. 1) Please explain when the forecast of customer additions was prepared. Did housing starts decline as expected in 2009? If not, please explain why the forecast of customer additions for 2010 remains appropriate.

RESPONSE

The forecast of 2010 customer additions was prepared during August 2009.

Franchise area housing starts in 2009 did decline, as expected, but were below the estimate in Exhibit B, Tab 1, Schedule 4, Table 1, Column 7.

Housing starts is one factor considered when developing the customer additions forecast along with a number of other economic indicators. Please see Exhibit I, Tab 7, Schedule 2, VECC Interrogatory #2(c). Economic inputs along with feedback from builders and regional operations form the basis for a bottom up forecast of expected customer additions.

The Company believes the 2010 forecast of customer additions remains appropriate.

Witnesses: J. Denomy
S. Murray

CCC INTERROGATORY #3

INTERROGATORY

(B/T1/S4/p. 7) Has EGD prepared an updated forecast of customer additions for 2010 relative to that provided on Table 2? If so, please provide.

RESPONSE

At this time, the Company does not have an updated forecast of customer additions for 2010 relative to Table 2 of Exhibit B, Tab 1, Schedule 4. The Company feels that this forecast remains appropriate as explained in Exhibit I, Tab 4, Schedule 3, CCC Interrogatory #2.

Witnesses: J. Denomy
S. Murray

CCC INTERROGATORY #4

INTERROGATORY

(B/T1/S5/p. 11) Please explain, in detail, how the 13.7 10^6m^3 adjustment for DSM initiatives was derived.

RESPONSE

Table 1 below explains the impact of incremental DSM initiatives on changes in residential customer consumption between the 2010 Budget and 2009 Estimate.

Column 1 indicates the 2010 budget's forecast of incremental DSM volumes of 13.7 10^6m^3 that have been developed using the Company's DSM Initiatives reported in Columns 2 to 5.

In a manner consistent with previous filings (e.g. EB-2008-0219, Exhibit I, Tab 7, Schedule 6, part d, etc.), the difference between the Bridge Year Estimate's fully effective (Column 2) and partially effective DSM targets (Column 3) is added to the 2010 Test Year's partially effective DSM target (Column 5) resulting in the expected incremental DSM volume savings forecast for 2010, as reported in Column 1 of Table 1.

The DSM volume forecast indicated in Column 1 has been calculated in a manner consistent with the actual billing consumption pattern. The reason for developing a partially effective annual impact is that not all 2010 DSM program participants will join the program commencing January 1, 2010; as a result the DSM program results corresponding to 12-months of volume savings will not be fully effective (i.e., reflected) in Year 2010's billing data.

Witnesses: I. Chan
T. Ladanyi

Table 1
Impact of DSM Initiatives on Changes in Residential Customer Consumption
Between 2010 Budget and 2009 Bridge Year Estimate (10^6m^3)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	=Col. 2-Col. 3+Col. 5	Company's DSM Initiative	Company's DSM Initiative	Company's DSM Initiative	Company's DSM Initiative
Sector	2010 Budget	2009 Fully Effective DSM Target*	2009 Partially Effective DSM Target	2010 Fully Effective DSM Target*	2010 Partially Effective DSM Target
Residential - Rate 1	(13.7)	(15.1)	(8.2)	(12.5)	(6.8)

*These fully effective DSM target volumes represent 75% of the total TRC target

Witnesses: I. Chan
T. Ladanyi

CCC INTERROGATORY #5

INTERROGATORY

(B/T3/S1/p. 2) Please explain how the estimated annual benefit to ratepayers related to pension costs was derived. Please include all assumptions. Why is this a “benefit” to ratepayers.

RESPONSE

The benefit arises in the form of cost avoidance, rather than by way of a direct credit to revenue requirement. Absent the surplus that was maintained by the plan, the minimum contribution requirement would have been the annual service cost, which would have averaged approximately $13 million for the years 2004 to 2008 and would have been included in the revenue requirement.

Please also refer to the response to Board Staff Interrogatory #6 at Exhibit I, Tab 1, Schedule 6.

Witnesses: J. Haberbusch
N. Kishinchandani

CCC INTERROGATORY #6

INTERROGATORY

(B/T3/S1, p. 6) The evidence states that the "meltdown" in financial markets over the past year was broad based and impacted virtually all segments of the economy. In addition, the evidence states that these events were clearly beyond the control of and could not have been reasonable foreseen by EGD's management. How does EGD differentiate between ongoing changes that occur in the economy and the recent downturn? When economic conditions are better than expected at the time of a rate application, and load subsequently increases as a result, why shouldn't EGD's ratepayers get the benefit of all of that increased revenue?

RESPONSE

The basis of differentiation between ongoing changes in the economy and the recent downturn lies in the magnitude of decline in financial markets that was experienced recently and that was unprecedented for decades.

The impact of load factor on revenue operates in accordance with the terms of the incentive regulation formula. It is not a cost, is not intended to operate as a Z-factor and thus is not comparable with the manner of treatment of pension costs.

The benefit to ratepayers during a period of fund surplus is explained in CCC Interrogatory #5, filed at Exhibit I, Tab 4, Schedule 5.

Witnesses: J. Haberbusch
N. Kishinchandani

CCC INTERROGATORY #7

INTERROGATORY

(B/T3/S1) Please indicate when the most recent Mercer valuation will be completed.

RESPONSE

The Mercer valuation as at December 31, 2009 is not expected to be available any earlier than April, 2010.

Witnesses: J. Haberbusch
N. Kishinchandani

CCC INTERROGATORY #8

INTERROGATORY

(B/T3/S1/p. 6) Given the statement that the Company's contribution requirements during 2010 may be significantly less than those which would have been required under the December 31, 2008 valuation, please provide evidence to demonstrate that EGD has met the materiality threshold as set out in the IRM plan.

RESPONSE

The materiality threshold cannot be determined until after the December 31, 2009 valuation becomes available in April 2010.

Witnesses: J. Haberbusch
N. Kishinchandani

CCC INTERROGATORY #9

INTERROGATORY

(B/T3/S2) Please indicate to what extent EGD's "Sewer Lateral Initiative" is being mandated by legislative or regulatory requirements. Please explain why these activities are not within the context of EGD's normal business requirements.

RESPONSE

There are no current legislative or regulatory requirements that mandate that Enbridge undertake its sewer lateral initiative. That does not, however, take away from the fact that it is necessary for Enbridge to take proactive steps to address crossbore issues and reduce the chances of any serious incidents. The Technical Standards and Safety Authority ("TSSA") is supportive of the Company's efforts to implement a plan to address the crossbore risk.

These activities and their associated costs are prudent and reasonable. The activities and costs are not part of "Enbridge's normal business requirements". The sewer lateral initiative is comprised of new activities that were not forecast at the time that the IR settlement was reached. The activities are not "normal" in that they are not related to the ordinary operations of the Company, but instead are extraordinary activities to address emerging safety concerns.

Witnesses: C. Clark
L. Lawler

CCC INTERROGATORY #10

INTERROGATORY

Please explain what relief EGD is seeking from in the panel with respect to the cost of capital. Please explain, how, if at all, EGD sees the Board's most recent cost of capital report impacting this application.

RESPONSE

The Company recently responded to a letter sent to the Board by counsel for the Industrial Gas Users Association in connection with this matter. EGD's response letter is attached for reference. At this time, the matter is still pending comment from the Board. The attached letter sets out EGD's position regarding consideration of cost of capital (specifically, return on equity for the purposes of earnings sharing calculations) by the panel in this case.

Witnesses: J. Denomy
M. Lister

AIRD & BERLIS LLP

Barristers and Solicitors

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January 29, 2010

Kirsten Walli, Board Secretary
Ontario Energy Board
P.O. Box 2319, 26th Floor
2300 Yonge Street
Toronto, Ontario
M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. – 2010 Rate Adjustment
EB-2009-0172

We have received a copy of the letter dated January 27, 2010 that was sent to the Board by counsel for the Industrial Gas Users Association in connection with this matter. In that letter, IGUA questions whether the Return on Equity to be used for the purposes of a 2010 earnings sharing calculation should be determined in accordance with the Board's recent decision in EB-2009-0084.

During the EB-2009-0084 proceeding (in other words, at a time when the outcome of the proceeding was not known) Enbridge was clear and consistent in stating that, given the provisions of the EB-2007-0615 Settlement Agreement, the outcome of the proceeding would apply to the earnings sharing calculation. This was stated during the EB-2009-0084 proceeding both in Enbridge's Written Comments filed on September 9, 2009 and in Enbridge's Final Written Comments filed on October 26, 2009. At no time before the outcome of the EB-2009-0084 proceeding was known did any party take issue with Enbridge's statements in this regard.

On January 22, 2010, Enbridge updated its 2010 Rate Adjustment evidence to reflect the EB-2009-0084 decision. In doing so, Enbridge repeated the statement made in its EB-2009-0084 Final Written Comments that the Board-approved ROE would be effective for the purposes of the earnings sharing calculation. Enbridge also reiterated that it does not seek to reopen the EB-2007-0615 Settlement Agreement as a result of the EB-2009-0084 decision - the use of the recently approved ROE methodology for the purposes of the earnings sharing calculation is based on the wording of the Settlement Agreement as it stands.

Enbridge was not aware that any issue would be taken with the update to its evidence that repeated comments made in the EB-2009-0084 proceeding. However, in its January 27th letter, IGUA indicated that it does not accept that the EB-2007-0615 Settlement Agreement provides for earnings sharing calculations based on the current Board-approved mechanism.

IGUA submits that Enbridge should seek to add to the Issues List for the 2010 Rate Adjustment an issue about the appropriate ROE to be used for the purposes of the earnings sharing calculation. No other party has taken this position. All the same, though, Enbridge agrees with IGUA's view that any issue about the appropriate ROE to be used for the earnings sharing calculation should not be deferred for consideration in the context of the next earnings sharing determination. In addition to IGUA's point about the need for certainty, Enbridge observes that section 11.1 of the EB-2007-0615 Settlement Agreement allows only an abbreviated time-line for consideration of the earnings sharing calculation: the calculation is to be filed as soon as is reasonably possible after year-end financial results have been made public, with a view to clearance of the Earnings Sharing Mechanism Deferral Account no later than the time of the July 1st Quarterly Rate Adjustment.

In short, given that IGUA has raised an issue about the appropriate ROE to be used for the 2010 earnings sharing calculation, it seems that the issue should be added to the Issues List for this proceeding. Enbridge submits that the point can be addressed by adding the following under the heading "Other Issues" in the Final Issues List:

> What is the appropriate ROE to be used in the 2010 earnings sharing calculation?

The date set out in Procedural Order No. 3 for interrogatories on Enbridge's pre-filed evidence has already passed. If there are further interrogatories by reason of the addition of the above issue to the Issues List, Enbridge proposes that such questions be provided by February 5th and that answers be given before or at the Technical Conference scheduled for February 11th and 12th.

If you have any questions in this regard, please do not hesitate to contact us.

Yours truly,

AIRD & BERLIS LLP

Fred D. Cass

FDC/

c.c. N. Ryckman/R. Bourke
All intervenors in EB-2009-0172

CME INTERROGATORY #1

INTERROGATORY

Issue 4 – Customer Additions

Reference: Exhibit B, Tab 1, Sch. 2, page 1 of 9, column 3, line 17
Exhibit B, Tab 1, Sch. 4, page 1
Exhibit B, Tab 1, Sch. 5, page 8
Exhibit B, Tab 1, Sch. 5, Appendix B, page 1

The company is forecasting 32,379 Customer Additions for 2010. The information at Exhibit B, Tab 1, Schedule 5, Appendix A, page 8, indicates estimated average additions for 2009 over 2008 of almost 36,000 customers. The 4 month actual/10 month forecast amount at Exhibit B, Tab 1, Schedule 5, page 1 is 33,268 Customer Additions. Please provide the following information:

(a) Now that the 2009 year is over, what is the actual number of Customer Additions for 2009 over 2008?

(b) Please provide the 2010 distribution revenue requirement impact and rate impacts of a finding that there will be about 36,000 Customer Additions in 2010.

RESPONSE

a) Please refer to the response to Undertaking TCU-1.2, which references the updated responses to BOMA Interrogatories #2 (c) and #4 (b) at Exhibit I, Tab 3, Schedules 2 and 4, respectively.

b) The Company is proposing a 2010 distribution revenue requirement of $1,003.3 million based on a customer addition forecast of 32,379. Based on a customer addition forecast of 36,000, the 2010 distribution revenue requirement would increase by approximately $0.7 million to $1,004.0. This increase in revenue requirement of $0.7 million would have a negligible effect on the rate impacts for all customer classes compared to those proposed at Exhibit B, Tab 4, Schedule 1, page 3.

Witnesses: I. Chan, J. Denomy, T. Ladanyi, D. Small, K. Culbert, A Kacicnik, S. Murray

CME INTERROGATORY #2

INTERROGATORY

Issue 5 – Gas Volume Budget

Reference: Exhibit B, Tab 1, Sch. 5, page 1
Exhibit B, Tab 1, Sch. 5, Appendix A, pages 9 to 14

The contract volume budget for 2010 of 2008.6 10^6m^3 is below the 2009 bridge year estimate of 2118.4 10^6m^3 and well below the 2008 actual contract volumes of 3101.5 10^6m^3. Please provide the following information:

(a) Please show the impact on contract rates of an increase in the contract volume budget for 2010 of 500 10^6m^3.

RESPONSE

Table 1 below presents the requested approximate average rate impacts of an increase in the contract volume budget for 2010 of 500 10^6m^3. The rate class breakdown of 500 10^6m^3 is assumed to be consistent with the current profile of 2010 contract volume budget.

Please note that the assumed addition of 500 10^6m^3 in contract volumes is significant and not reflective of past results or current marketplace environment. For example, 500 10^6m^3 in additional volume is roughly equal to the total annual consumption of Rate 110 customers (239 customers and 563 10^6m^3 annual volume) or Rate 115 customers (42 customers and 426 10^6m^3 annual volume).

Further, due to time limitations the Company assumed: a) the additional volume is added to the system without the addition of new customers, b) no impact on the proposed distribution revenue requirement, and c) negligible impact from the additional volume on the gas cost to operations budget.

The resulting approximate average rate impacts by rate class are as follows:

Witnesses: I. Chan
J. Collier
A. Kacicnik
T. Ladanyi

Table 1: 2010 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact
1	1.6%
6	1.1%
9	1.0%
100	0.4%
110	0.4%
115	0.3%
135	0.5%
145	0.6%
170	0.4%
200	0.3%
	Delivery Rate Impact
125	0.9%
300	0.9%

For comparison, the proposed average rate impacts resulting from the Company's application (as updated) are set out at Exhibit B, Tab 4, Schedule 1, page 3.

Also please note that:

i) the major reason for the decrease in the contract market volumes between 2009 Bridge Year Estimate and 2008 Actual on a weather-normalized basis is customer migration from contract rates to Rate 6 and to unbundled rates. The detailed comparison of 2009 Bridge Year Estimate and 2008 Actual volumes are provided at Exhibit B, Tab 1, Schedule 5, pages 32 to 35; and

ii) the weather normalized actual contract market volumes have been under the Board Approved Budget by more than 100 10^6m^3 each year from 2005 to 2008 as shown at Exhibit B, Tab 1, Schedule 5, Appendix A, page 25.

Witnesses: I. Chan
J. Collier
A. Kacicnik
T. Ladanyi

CME INTERROGATORY #3

INTERROGATORY

Issue 6 – Y Factor – Power Generation Projects

Reference: Exhibit B, Tab 1, Sch. 2, page 1, column 3, lines 7 and 22
Exhibit B, Tab 2, Sch. 1, pages 1 and 2

The evidence indicates that the Portlands Energy Centre and the Thorold Cogen continue to impose a subsidy burden on ratepayers and that the burden is increasing from $3.2M in 2009 to $3.6M in 2010. Please provide the following information:

(a) The economic feasibility calculations that EGD used at the outset of each of the projects over the time horizon then considered appropriate that indicate the year in which each of these facilities was originally expected to generate sufficient revenues to cover EGD's allowed returns;

(b) Please provide current estimates of the year in which each of these facilities will likely cease to be a subsidy burden on ratepayers and provide returns equal to or in excess of EGD's currently allowed returns.

The evidence refers to 2 new Power Generation-related pipeline projects, namely, the York Energy Centre and the Greenfield South Pipeline Projects. Please provide the following information:

(c) The economic feasibility analyses used to show the extent to which each of these projects is likely to be a subsidy burden on ratepayers in future years and the year in which each of these projects are expected to commence generating sufficient revenues to cover EGD's allowed returns.

(d) What contribution in aid, if any, does EGD expect to recover with respect to each of these projects?

Witnesses: K. Culbert
A. Kacicnik
S. Murray

RESPONSE

a) and b) The feasibility analysis for the Portlands Energy Centre yielded a Profitability Index (PI) = 1.0 after a contribution in aid of construction. The feasibility analysis for Thorold Cogen yielded a Profitability Index (PI) = 1.0. Both projects satisfied feasibility criteria in accordance with the Board's approved procedures as established in EBO 188: Natural Gas System Expansion, Report of the Board.

The feasibility analyses for the two projects were filed as part of Leave to Construct ("LTC") Applications. They are appended to this interrogatory response together with the Board's Decision and Order for each application.

It is important to highlight that the Y-factor for power generation projects derives the annual revenue requirement (i.e. costs) to be recovered in 2010 for these projects. The application of the IRM escalation formula together with Y and Z factor revenue requirement amounts determines the total level of 2010 revenue requirement as shown at Exhibit B, Tab 1, Schedule 2, page 1, Column 3. Subsequently, through the rate design process, which adheres to the Board approved principles and conventions, rates and revenues are set to recover the total 2010 revenue requirement.

As discussed in the balance of this response, there is no subsidy burden on other rates or ratepayers given that the annual revenues through Rate 125 demand charges for the Portlands Energy Centre and Thorold Cogen are sufficient to recover the Y-factor annual revenue requirement for these two projects.

The 2010 Y-factor revenue requirement, inclusive of allowed returns, for Portlands and Thorold power generation projects equals $3.6 million as shown at Exhibit B, Tab 1, Schedule 2, page 1, Row 22, Column 3.

The level of revenue through Rate 125 demand charges that the Company proposes to recover in 2010 from the Portlands Energy Centre and Thorold Cogen equals approximately $3.9 million, which is greater than the 2010 Y-factor annual revenue requirement by approximately $0.3 million.

The $3.9 million revenue from the two projects above is part of the $7.4 million in revenue the Company proposes to recover from four Rate 125 customers in 2010 as shown at Exhibit B, Tab 4, Schedule 5, page 1, Item 7, Column 4.

Witnesses: K. Culbert
A. Kacicnik
S. Murray

The $7.4 million in Rate 125 revenues is part of the $2,456.8 million in total revenue the Company proposes to recover in 2010 as shown at Exhibit B, Tab 4, Schedule 5, page 1, Item 16, Column 4.

The total 2010 revenue of $2,456.8 million equals the total 2010 revenue requirement of $2,456.8 million shown at Exhibit B, Tab 1, Schedule 2, page 1, Row 30, Column 3.

The derivation of Y-factor revenue requirement for power generation projects and the recovery of the same through rates are fully compliant with the Company's Incentive Regulation (IR) Settlement Agreement in EB-2007-0615.

c) and d) Please note that proposed completion dates for the York Energy Centre and the Greenfield South projects are in 2011. Hence, they are not part of the 2010 Y-factor revenue requirement for power generation projects. The Company is not requesting any approvals for these two projects as part of the 2010 Rate Adjustment Application.

An LTC Application for the York Energy Centre is presently in front of the Board. The projects economic feasibility evidence is filed at Exhibit E and can be found, along with all of the evidence in that proceeding, in the Board's webdrawer under docket EB-2009-0187.

An LTC Application for the Greenfield South project is yet to be filed.

Witnesses: K. Culbert
A. Kacicnik
S. Murray

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0305

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order pursuant to Section 90(1) of the *Ontario Energy Board Act, 1998,* granting leave to construct natural gas pipelines in the City of Toronto.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Enbridge Gas Distribution Inc. ("Enbridge") filed an application with the Ontario Energy Board on December 7, 2006, under section 90 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15, Schedule B, for an Order for Leave to Construct natural gas pipelines for the purpose of supplying gas to the already approved Portlands Energy Centre generating station ("Portlands") in the City of Toronto. Construction is scheduled to start in the summer of 2007, with a planned in-service date of February 2008.

For the reasons set out below, the Board finds the construction of the proposed pipelines to be in the public interest and grants the Leave to Construct on the terms and conditions set out in this Decision.

The Proposed Pipelines

The project involves the construction of two sections of pipeline. The north section consists of approximately 6.5 kilometres of pipeline parallel to a portion of Enbridge's existing Don Valley Line. The south section consists of approximately 2.9 kilometres of pipeline that would interconnect the Don Valley Line at Enbridge's station B regulator station and end at Portlands.

The north section route is located primarily on land in the former Hydro One corridor currently owned by Enbridge (north of Sheppard Avenue to the north limit of Highway 401) and the Hydro One corridor presently owned by the Ontario Realty Corporation ("ORC") (from the south limit of Highway 401 to Eglinton Avenue). The majority of the south section is on land located on road allowances with the exception of certain locations owned by the City of Toronto Economic Development Corporation, the Toronto Port Authority and Ontario Power Generation Inc.

Maps showing the location of the two proposed pipelines are attached as Appendix "A".

The Parties

Three parties requested and were granted Intervenor status: Portlands Energy Centre, Toronto Economic Development Corporation ("TEDCO") and Union Gas Limited ("Union"). A late Intervenor status was granted to Mr. Paul Beatty, a resident of Scarborough, whose residence bordered to the eastern boundary of the northern section of the pipeline project. Mr. Beatty opposed the proposed location of the pipeline. The other Intervenors generally supported the project although TEDCO had concerns with certain aspects of the form of easement agreement. Both these matters are dealt with later in this Decision.

The Board granted Observer status to the City of Toronto ("the City"), Mr. John Butler and Mr. David Elder, both local residents. The City requested undertakings from Enbridge with respect to the type of drawings to be provided. That request will be dealt with later in this Decision.

Board Staff Counsel made written submissions on the legal test to be applied in Applications for Leave to Construct under sections 90 and 91 of the Act, which were circulated to the Applicant and all Intervenors. Board Staff Counsel also submitted proposed conditions of approval.

The Board also received a letter of comment from Mr. Peter Tabuns, MPP for Toronto-Danforth and Mr. Jack Layton, MP for Toronto-Danforth and the Toronto Energy Coalition ("TEC") and a letter of comment from Ms. Christine Becker, an affected resident. TEC requested that the Board deny the Application based upon the emissions that would be created by the generating facility. Ms. Becker commented on the public consultation and notification and on the proposed location of the pipeline.

The Public Interest Test

This is an Application under section 90 of the Ontario Energy Board Act seeking a Leave to Construct Order with respect to two natural gas pipeline projects. Section 96 of the Act provides that the Board shall make an Order granting leave if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the Board typically examines the need for the project, the economics of the project, the environmental impact and the impact on land owners. Each of these factors will be considered in turn.

The Need for the Project

Portlands is in the process of constructing a new 550 Megawatt high-efficiency natural gas fired generation plant and has signed a 20 year Accelerated Clean Energy Supply agreement with the Ontario Power Authority. The anticipated construction cost is $730 million with an initial in-service date of June 1, 2008. When fully complete, the Portlands facility will be capable of providing 25% of Central Toronto's electricity needs (Ex. A, Tab 3, Schedule 4, p. 2 of 4).

Enbridge and Portlands have entered into a 20 year gas delivery agreement (Ex. A, Tab 3, Schedule 5) based upon the Board approved Rate 125[1]. The hourly contract demand is 116 079 m^3 and the daily demand for the Portlands is 2 785 885 m^3. In addition, the customer requires a minimum pressure of 200 psi or 1379 kPa in order to operate its facility. The Gas Delivery Agreement requires Enbridge to deliver gas to Portlands on February 1, 2008 (Ex. A, Tab 3, Schedule 5, p. 56 of 58).

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[1] *Enbridge Gas Distribution Inc.,* Decision with Reasons, EB-2005-0001, (February 9, 2006)

Enbridge's existing high pressure distribution system is supplied by the TransCanada Pipelines ("TCPL") system at the Victoria Square Gate Station. In 1971, a NPS 30 pipeline (the "Don Valley Line") was constructed from Victoria Square Gate Station to Enbridge's Station B located on Eastern Avenue (Ex. A, Tab 3, Schedule 2).

The Don Valley Line requires reinforcement, or looping to provide adequate pressure at Station B to meet Portlands' needs. In addition, the existing distribution system downstream of Station B does not have the ability to meet Portlands' requirements. Enbridge embarked on a process of developing a project that would meet the needs of Portlands in an environmentally acceptable and cost-effective manner.

The North Section: The maximum operating pressure of the Don Valley Line is 450 psi (3100 kPa). Station B has a minimum inlet pressure of 225 psi (1550 kPa). The minimum inlet pressure is required for the station to have the capability to supply natural gas in sufficient quantities and at sufficient pressures to the downstream distribution pipeline system. Without the Portlands load, the existing Don Valley Line is able to provide the required minimum inlet pressure at Station B with a Victoria Square Gate Station outlet pressure of 405 psi (2709 kPa) under Enbridge's system design conditions.

Enbridge examined the impact on pressures if the Portlands load is added and no reinforcement was undertaken. With an outlet pressure of 450 psi (3100 kPa) at Victoria Square Gate Station (the maximum operating pressure of the Don Valley Line) the pressure at Station B inlet pressure drops to 210 psi (1445 kPa) with the addition of the Portlands load. Unless reinforcement of the Don Valley Line was to occur, the Portlands load would remove any existing flexibility in the distribution system and the inlet pressure would be unacceptably low at Station B. As such, it was necessary for Enbridge to consider various alternatives to deliver gas in the required quantity and at the required pressure to Station B. Enbridge determined that the proposed North Section was the optimal choice.

After considering alternatives, Enbridge chose the North Section as the preferred alternative because the Environmental Assessment Reports identified the North Section as the preferred route. It also meets the contractual demands of Portlands and maintains the operational characteristics of the distribution system. In addition, it does not conflict with possible future use of the Hydro One corridor. It is lower in cost and it can meet the required timeline.

The South Section: Enbridge's current high pressure distribution system includes a NPS 24 pipeline approximately 3 500 m in length from Station B to the now abandoned R.L. Hearn Generating Station that was installed in 1971. This existing pipeline network downstream of Station B is not adequate to meet the requirements of Portlands as it currently operates with a maximum pressure of 125 psi (860 kPa). Portlands' minimum required delivery pressure is 200 psi (1378 kPa). Enbridge considered pressure elevating the existing piping infrastructure. The evidence (Ex. C, Tab 1, Schedule 1, pp. 4 - 6) described several issues with the pressure elevation option. In the end, the option to pressure elevate was not acceptable to Enbridge.

The evidence clearly supports a finding that there is a need for both north and south pipeline projects. The existing pipelines do not have the capacity to support Portlands' requirements. The need for new generation to meet the growing electricity requirements of Toronto is serious and well recognized.

The Proposed Routing

The routing of the northern section of pipeline was contested by Paul Beatty, a resident of the area. The proposed route as indicated in Appendix "A" is in a Hydro One transmission corridor. The current pipe is on the western side of the transmission corridor and Mr. Beatty argues that the new pipe should be in the east side of the corridor.

The Enbridge response was that Hydro One was not prepared to route the pipeline on the eastern side of the right-of-way because they wished to preserve that space for future development. Accordingly, locating the new pipe on the eastern portion of the Hydro One right-of-way was not something that was investigated further.

Mr. Beatty also argued that the proposed location was too close to properties on the western perimeter of the corridor. He noted that when the Board approved the original pipeline in 1971, it imposed a condition that the pipe be no closer than 35 feet to the property line.

With respect to the 35 ft. buffer that the Board mandated in 1971[2] Enbridge noted that the Technical Standards Safety Authority ("TSSA") does not provide any recommendation for set back on pipelines operating at less than 40% Specified Minimum Yield Strength ("SMYS") and therefore permits development up to edge of the

[2] *The Consumers' Gas Company,* Order Granting Leave to Construct, EBLO 142, (April 8, 1971)

pipeline right-of-way[3]. Accordingly, the proposed route which was reviewed as part of the Ontario Pipeline Coordinating Committee ("OPCC") process was endorsed by the TSSA:

> "We have reviewed the documentation related to the EB-2006-0305 Application received from Enbridge Consumers Gas and found that the design specifications for the pipeline meet or exceed the requirements of the Ontario Regulation on Oil and Gas Pipeline Systems. (O.Reg. 210/01). We also agree with the route selected, as it appears as the best alternative for the pipeline installation." (Ex. J.1, p. 22 of 99).

The Board appreciates the submissions made by Mr. Beatty, and the time spent compiling the materials that he shared with the Board. While the Board notes the concerns expressed by Mr. Beatty, the Board is satisfied that the evidence establishes that the route selected was the best alternative for the location of the northern section of the pipeline.

No intervenor objected to the location of the southern section of the pipeline. The Board is satisfied that the evidence establishes that the route selected was the best alternative for the location of the southern section of the pipeline.

Environmental Assessment

Both the North and South Pipeline Projects meet all the environmental assessment requirements. Enbridge was required to conduct a Category B Environmental Assessment pursuant to the Class Environmental Assessment Act for Management Board Secretariat and the Ontario Realty Corporation Act (April, 2004) because of the need to requirement an easement from the ORC.

Enbridge retained Dillon Consulting Ltd ("Dillon") and Stantec Consulting Ltd. ("Stantec") to undertake an environmental and socio-economic impact assessment to select preferred routes for north and south sections respectively. The assessment was carried out in accordance with the Board's *Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario* (May 2003) (the "Board's Environmental Guidelines"). The results of the assessment are documented in "Toronto Portlands System Reinforcement Project: South Section", Stantec Consulting Ltd., December 2006 ("Stantec Report") (Ex. B, Tab 2, Schedule 4) and in "Updating Study-Environmental and Socio-economic Impact Assessment, Toronto

[3] PI-98/01 "Guidelines for Locating New Oil and Gas Pipeline Facilities", August 19, 1998.

Portlands System Reinforcement Pipeline: North End", Dillon Consulting Ltd., November 2006 ("Dillon Report") (Ex. B, Tab 2, Schedule 3).

Both the Stantec Report and the Dillon Report were reviewed by the OPCC.

Regarding the north section Mr. Guiseppe Muraca, the Environmental Consultant from Dillon, stated that the proposed route was environmentally acceptable and the environmental assessment was complete and it accords with the Board's Environmental Guidelines. Enbridge indicated that it was committed to implementing the mitigation recommended by Dillon.

With respect to the routing of the south section of the pipeline, Enbridge engaged an independent consultant, Stantec with extensive experience to develop the preferred route. Stantec undertook this work in compliance with the Board's Environmental Guidelines. As part of this process, Stantec undertook extensive consultation with government agencies and the public. Three public meetings were held to inform the public of the project and solicit input. Details of public consultation program may be found at section 4.0 of the Environmental Report prepared by Stantec. The Stantec Report indicates that nine pipeline segments were considered and in the end the route indicated in Appendix "A" was chosen because it was located in an existing roadway, minimized disruptions to socio-economic features and had public support. Mr. David Wesenger the Environmental Consultant from Stantec confirmed that the proposed route was an environmentally acceptable alternative using the proposed mitigation techniques included in the Stantec Report and rigid construction practice. Enbridge indicated that it was committed to implementing the mitigation measures in the Stantec Report.

Economics of the Project

Enbridge originally estimated that the project cost was $41.7 million but later advised that the cost had increased by $6.8 million due to an increase in the cost of acquiring land rights from the Ontario Realty Corporation and Hydro One. However, Enbridge advised that the economic feasibility of the project would not be impacted negatively because the increased costs would be added to the contribution in aid of construction made by Portlands.

The economic feasibility of the Project was determined in accordance with the Board's approved procedures as established in EBO 188 and the Board's approval in EB-2005-0001. The economic analysis indicated that a contribution in aid of construction is required from Portlands in order for the net present value ("NPV") to equal zero or the profitability index ("PI") to equal one. A PI of 1.0 indicates that the Project is economic for Enbridge.

In order to ensure that the Project remains economic regardless of increases in cost, Enbridge has negotiated with Portlands a term in the Gas Delivery Agreement that provides that the "contribution in aid of construction will be re-calculated at the end of the Project based upon the actual cost of construction". Enbridge confirmed that the contribution in aid of construction will be re-calculated or increased to ensure that a PI of 1.0 is maintained. Accordingly, other ratepayers are not at risk and there is no concern with cross-subsidization. Put differently other ratepayers are not at risk for any costs overruns associated with this Project given the automatic adjustment clause that is found in the Gas Delivery Agreement (Ex. A, Tab 3, Schedule 5, p. 39 of 58, section (f)).

It is also important to note that the revenue stream from Portlands is not subject to variability because of variability in gas consumption by Portlands. The revenues to be earned by Enbridge are based on contract demand volumes, not actual consumption. This ensures Portlands' predicted revenues going forward and recovery over the 20 year horizon.

Enbridge has also secured financial assurances from Portlands in the form of guarantees from the parents of Portlands, that ensure that Enbridge is protected through to the conclusion of the Gas Delivery Agreement. In its argument, Enbridge filed a letter from Portlands responding to issues raised by the Board during a hearing. The letter confirmed the allocation of risk and Portlands' commitment to the Project.

Land Issues and Form of Easement

TEDCO is an Intervenor in this proceeding and participated in the oral hearing. Enbridge requires an easement from TEDCO with respect to three sections of land. Two sections are located immediately north and south of the shipping channel where Enbridge will be using a horizontal directional drill to cross underneath the shipping channel. The remaining easement required by Enbridge is within the Portlands generating facility where Enbridge currently has an existing distribution pipeline.

Section 97 of the OEB Act provides that a leave to construct will not be granted until the Applicant has satisfied the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board.

TEDCO asked the Board to modify the form of agreement proposed by Enbridge with respect to two clauses. First, TEDCO took issue with the environmental cause, (clause 7) in the Standard Form Agreement whereby the landowner represents and warrants that the lands do not contain hazardous substance. Enbridge responded that the Board should not be concerned about the specific terms of the form of easement at this point stating that the form was simply "a starting point" in the negotiations.

Enbridge submits that it is not the Board's role in a leave to construct proceedings to intervene in the negotiations between the Applicant and the landowners. In the event that the parties are unable to negotiate an agreement, then alternatives are considered which may include different routes or even expropriation. The OEB Act provides a mechanism to resolve such disputes through an expropriation proceeding. That mechanism provides for compensation under the Expropriation Act by the Ontario Municipal Board ("OMB") and not the OEB. Accordingly, Enbridge argues that the legislation limits this Board's role to the determination of whether expropriation of land is required, not to determine whether the amount of compensation is appropriate. Enbridge also points out that the form of easement being proposed in this proceeding was the form approved by the Board in Scarborough System Reinforcement Application EB-2006-0066[4] as well as the Goreway Station Application in EB-2005-0539[5].

With respect to the environmental clause, Enbridge says that the Transferor is in the best position to know the environmental condition of the property in question. Accordingly, to the extent that representation is false, the Transferor should be responsible for the removal of hazardous substances. With respect to the indemnity, Enbridge says that the landowner is free to negotiate additional terms with Enbridge and the absence of such clause in the proposed Agreement in no way prohibits TEDCO from negotiating such a clause.

Section 97 of the Ontario Energy Board Act reads:

> "In an application under section 90, 91 or 92, leave to construct shall not be granted until the applicant satisfies the Board that it has offered or will offer to each owner of land affected by the approved route or location an agreement in a form approved by the Board."

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[4] *Enbridge Gas Distribution Inc.,* Decision and Order, EB-2006-0066, (November 30, 2006)

[5] *Enbridge Gas Distribution Inc.,* Decision and Order, EB-2005-0539, (July 10, 2006)

In the course of cross-examination, Enbridge testified that:

- The form of easement agreement filed by Enbridge is offered to all landowners (Transcript Vol. 1, p.92);
- The standard form agreement filed by Enbridge is generally the same agreement that the utility files with the Board on every leave to construct application (Transcript Vol. 1, p. 96);
- The agreement is considered a 'benchmark' and is in all respects open to negotiation between the parties (Transcript Vol. 1, p. 97);
- In most cases changes are made as a result of negotiations (Transcript Vol. 1, pp. 98-99);
- The agreement filed by Enbridge does not contain an indemnification paragraph (Transcript Vol. 1, pp. 102-103);
- The agreement filed by Enbridge contains paragraphs which permit Enbridge to select the route and obtain an indemnity from the landowner for the removal of any hazardous substances found on the land (Transcript Vol. 1, pp. 99-100).

When considering the standard form agreement to be offered to affected landowners, the Board considers the agreement anew and in the context of the application in which it has been filed. The Board approves a standard form agreement which represents the initial offering to the affected landowner. Once the Board is satisfied with the standard form agreement, and in this case the Board is satisfied with the form as filed by Enbridge, the parties are free to negotiate whatever terms they believe to be necessary to protect their specific interests. The Board does not become involved in the detailed negotiation of the clauses in the agreements between one landowner and the Applicant. It is also accepted that a review by this Board under Section 97 does not extend to the amount of compensation or the structure of compensation arrangements.[6]

At the time of the hearing Enbridge had not finalized any of the landowner easement agreements but remained optimistic that they would be concluded well in advance of the planned construction start on July 1, 2007. The only possible exception was Studios of America. Enbridge advised the Board that the Board would be updated on the status of all easement agreements.

[6] *Union Gas Limited* , Decision and Order, EB-2005-0550, (June 12, 2006)

The Emissions Issue

The Board received a letter of public comment on February 7, 2007 from Mr. Peter Tabuns, (MPP Toronto-Danforth), Mr. Jack Layton, (MP Toronto-Danforth) and the Toronto Energy Coalition ("TEC"). TEC requested the Board to deny this Application based upon the potential environmental impacts of the Portlands generating facility. Enbridge asked the Board to disregard these comments because "a [belief] that the construction operation of a plant will result in emissions has nothing to do with the pipeline application before the Board".

A similar concern was raised in the Application by the Greenfield Energy Centre Limited in a Leave to Construct a natural gas pipeline in the Township of St. Clair, Ontario. In the Board's Decision Order dated January 6, 2006, the Board clearly separated the environmental aspects of the pipeline construction from those related to the power station itself. The Board stated:

> "To be clear, only those effects that are additive or interact with the effects that have already been identified as resulting from the pipeline construction are to be considered under cumulative effects."[7]

The Board further stated that it has no jurisdiction to consider the arguments of the Intervenors in this regard:

> "In the Board's view, the law is clear that the jurisdiction on environmental matters associated with the power station falls under the *Environmental Assessment Act* administered by the Ministry of the Environment, and not the Ontario Energy Board. The process under the provincial Environmental Assessment Act in relation to the GEC generating station has been concluded ." (pp. 17-18)

This Decision was upheld by the Divisional Court.[8]

The Board Staff Counsel filed as part of its argument draft conditions of approval. The last draft condition was unique to this proceeding and resulted from a request by the City of Toronto, an Observer in this case, that the condition be followed including:

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7 *Greenfield Energy Centre Limited Partnership,* Decision and Order, RP-2005-0022/EB-2005-0441/EB-2005-0442/EB-2005-0443/EB-2005-0444, (January 6, 2006) at p.10.

8 *Power Workers' Union*, *CUPE Local 1000 v. Ontario Energy Board* (2006), 214 O.A.C. 208, [2006] O.J. No. 2997 (Div. Ct.)

"That Enbridge Gas Distribution Inc. provide, within thirty (30) days of the completion of its construction (defined for the purposes of the public highway as the backfill and temporary patch of any excavation) to the City of Toronto and the property owners over which the pipeline will be built:

- Drawings certified by an Ontario Land Surveyor accurately showing the location of the constructed pipeline; or

- A record drawing as defined by the Association of Professional Engineers of Ontario accurately showing the location of the constructed pipeline."

Enbridge did not oppose a condition but noted that the cost of Ontario Land Surveyor would be approximately $240,000. Under the terms of the Gas Delivery Agreement this cost would become part of the project. As a result, neither Enbridge nor the ratepayers would incur the costs. Enbridge did state that they did not support the inclusion of this condition as a standard practice in other projects. Finally, Enbridge noted that the option for surveyor drawings, rather than engineer record drawings would appear to better meet the City of Toronto's request to tie the location of the pipeline into the property bars (Transcript Volume 1, p. 119).

While this additional cost may not be immediately borne by Enbridge or Enbridge's other ratepayers, in the long run such costs form part of utility's cost of service and are ultimately paid by ratepayers. There is not sufficient evidence before us to justify this additional cost. The interests of the City of Toronto can be protected through less costly means. It is significant that the City of Toronto did not appear at the hearing to support its position or present argument. In the circumstances the Board is not prepared to grant the request by the City of Toronto and directs that the last paragraph contained in the draft conditions of approval, filed by Board Staff Counsel, be removed.

Orders Granted

For the Reasons indicated, the Board finds that the two pipeline projects being proposed by Enbridge in this proceeding are in the public interest and grants the Leave to Construct subject to the conditions set out in Appendix "B".

Filed: 2010-02-09
EB-2009-0172
Exhibit I
Tab 5
Schedule 3
Attachment 1
Page 13 of 21

THE BOARD ORDERS THAT:

1. Enbridge Gas Distribution Inc. is granted leave, pursuant to subsection 90 (1) of the Act, to construct approximately 6.5 kilometres of NPS 36 pipeline to parallel a portion of Enbridge's existing NPS 30 XHP Don Valley Line and approximately 2.9 kilometres of NPS 20 XHP steel pipeline that would interconnect the Don Valley Line at Enbridge's Station B regulator station and would terminate at the Portlands Energy Centre in the City of Toronto, subject to the conditions of approval set forth in Appendix "B".

2. Eligible intervenors who seek an award of costs incurred to date shall file their cost submissions in accordance with the *Practice Direction on Cost Awards* with the Board Secretary and with Enbridge Gas Distribution Inc. within 15 days of the date of this Decision. Enbridge Gas Distribution Inc. may make submissions regarding the cost claims within 30 days of the Decision and the intervenors may reply within 45 days of the Decision. A decision and order regarding cost awards will be issued at a later date. Upon receipt of the Board's cost award decision and order, Enbridge Gas Distribution Inc. shall pay any awarded costs with dispatch.

3. Enbridge Gas Distribution Inc. shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, June 1, 2007

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

APPENDIX "A"

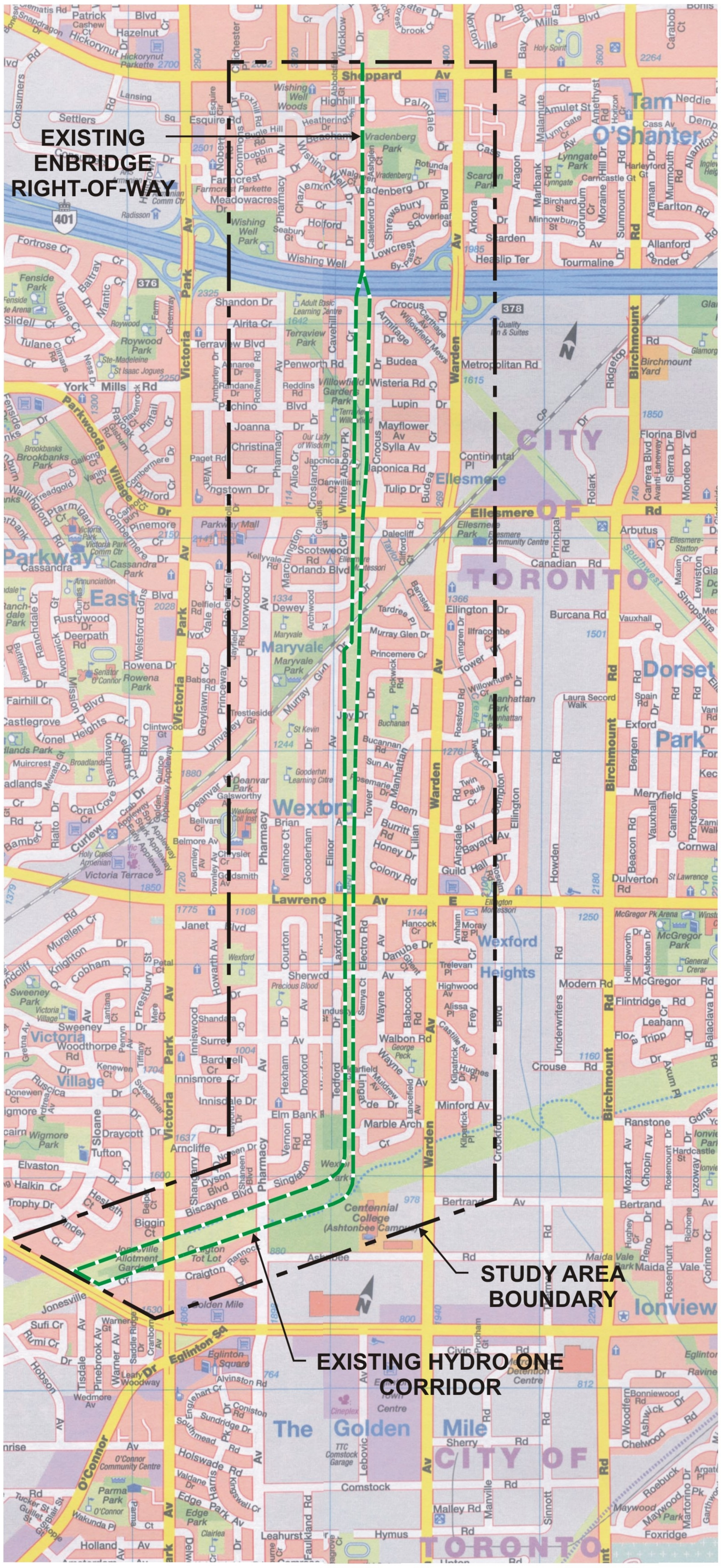
TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2006-0305

DATED June 1, 2007

MAPS OF THE PIPELINE ROUTES

VICTORIA SQUARE GATE
MARKHAM GATE
STN. B
PEC
STN. 'B'
NPS 30
EASTERN
AVE.
NPS 24
NPS 12
NPS 16
NPS 20
LAKE SHORE
BOOTH
LOGAN
BLVD.
ST.
BOUCHETTE ST.
BASIN
COMISSIONER
SAULTER ST. S.
WATER - CHANNEL
UNWIN
SHEPPARD
PHARMACY
YORK MILLS
RD.
DVP
VICTORIA PARK
NPS 36
HWY. 401
ELLESMERE
WARDEN
BIRCHMOUNT
LAWRENCE
E.
EGLINTON
OPTION 'A'
TORONTO - HP & XHP
LEGEND
EXIST NPS 36 & LARGER XHP
EXIST NPS 30 XHP
EXIST NPS 24 & 26 XHP
EXIST NPS 12 TO 20 XHP
EXIST NPS 30 & LARGER HP
EXIST NPS 12 TO 24 HP
TCPL & UNION GAS
PROP NPS 36 & LARGER XHP
PROP NPS 12 TO 20 XHP
GATE STATIONS
SCALE
0 1 2 3 4 5 6 7 8 9 10 kilometres
ENBRIDGE
AREA 10
DWG NO. 0036
DRAWING: METRO OEB



1:25,000 (Approx.)

ENBRIDGE

TORONTO SYSTEM
REINFORCEMENT STUDY

STUDY AREA A

SENES Consultants	Project Number	Figure
	33485	4

Note: *The features on this map are for illustrative purposes only. Original source should be referenced for actual location and boundaries.*

Study Area
Preferred Route
Alternate Routes

Base Map Source: Northway-Photomap Inc.

REVISION NO.	REVISION DATE	DESCRIPTION	REVISED BY:
-	-	-	-

PROJECT NAME:
ENBRIDGE NATURAL GAS PIPELINE

CLIENT NAME:
ENBRIDGE

DATE INITIATED: **OCTOBER, 2006**
FILENAME: **60960211_05.cdr**

FIGURE NO. **A-2**

PRELIMINARY PREFERRED ROUTE AND ROUTE SEGMENTS

SCALE:	PROJECT NO.:
1:12,000	160960211

REV. NO.	SHEET NO.	CHECKED BY:	APPROVED:	DRAWN BY:
0	1 OF 1	MA	DPW	CEW

APPENDIX "B"

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2006- 0305

DATED JUNE 1, 2007

CONDITIONS OF APPROVAL

EB-2006-0305

Enbridge Gas Distribution Inc.
Toronto Portlands Reinforcement
Leave to Construct Application

Conditions of Approval

Leave to Construct

1 General Requirements

1.1 Enbridge Gas Distribution Inc. (“Enbridge”) shall construct the facilities and restore the land in accordance with its application and evidence filed in EB-2006-0305, except as modified by this Order and these Conditions of Approval.

1.2 Unless otherwise ordered by the Board, authorization for Leave to Construct shall terminate December 31, 2008, unless construction has commenced prior to then.

1.3 Except as modified by this Order, Enbridge shall implement all the recommendations of the Environmental Study Reports filed in the pre-filed evidence, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee (“OPCC”) review.

1.4 Enbridge shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, Enbridge shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

2 Project and Communications Requirements

2.1 The Board's designated representative for the purpose of these Conditions of Approval shall be the Manager, Facilities.

2.2 Enbridge shall designate a person as project engineer and shall provide the name of the individual to the Board’s designated representative. The project engineer will be responsible for the fulfilment of the Conditions of Approval on the construction site. Enbridge shall provide a copy of the Order and Conditions of Approval to the project engineer, within seven days of the Board’s Order being issued.

2.3 Enbridge shall give the Board's designated representative and the Chair of the OPCC ten days written notice in advance of the commencement of the construction.

2.4 Enbridge shall furnish the Board's designated representative with all reasonable assistance for ascertaining whether the work is being or has been performed in accordance with the Board's Order.

2.5 Enbridge shall file with the Board’s designated representative notice of the date on which the installed pipelines were tested, within one month after the final test date.

2.6 Enbridge shall furnish the Board’s designated representative with five copies of written confirmation of the completion of construction. A copy of the confirmation shall be provided to the Chair of the OPCC.

3 Monitoring and Reporting Requirements

3.1 Both during and after construction, Enbridge shall monitor the impacts of construction, and shall file four copies of both an interim and a final monitoring report with the Board. The interim monitoring report shall be filed within six months of the in-service date, and the final monitoring report shall be filed within fifteen months of the in-service date. Enbridge shall attach a log of all complaints that have been received to the interim and final monitoring reports. The log shall record the times of all complaints received, the substance of each complaint, the actions taken in response, and the reasons underlying such actions.

3.2 The interim monitoring report shall confirm Enbridge’s adherence to Condition 1.1 and shall include a description of the impacts noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the impacts of construction. This report shall describe any outstanding concerns identified during construction.

3.3 The final monitoring report shall describe the condition of any rehabilitated land and the effectiveness of any mitigation measures undertaken. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Any deficiency in compliance with any of the Conditions of Approval shall be explained.

4 Easement Agreements

4.1 Enbridge shall offer the form of agreement approved by the Board to each landowner, as may be required, along the route of the proposed work.

5 Other Approvals

5.1 Enbridge shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

ECONOMIC FEASIBILITY

METHODOLOGY

1. The overall feasibility of the project has been determined using the methodology that adheres to the parameters contained within the "Ontario Energy Board Guidelines for Assessing and Reporting on Natural System Expansion in Ontario" and as laid out in the Ontario Energy Board's EBO 188 "Report to the Board" dated January 30, 1998.

2. The economic feasibility of this project has been calculated by discounting the incremental cash flows over a 20 year customer revenue horizon. The resulting NPV represents both the economic feasibility of the project from the utility's perspective and its effect within the Rolling Project Portfolio. An NPV greater than zero indicates the project will have a positive contribution to the Rolling Project Portfolio and will be feasible from a utility cash flow perspective. Since the project NPV is less than zero, a contribution in aid of construction is required. The Customer has agreed to pay the contribution. Exhibit E, Tab 1, Schedule 2 details the NPV and the Customer contribution for the project.

KEY ASSUMPTIONS

Customer Revenue Horizon

3. The feasibility analysis for the project was based upon a 20-year customer revenue horizon. The first year revenue is calculated based on eight months as the Customer has requested a four month commissioning period.

Capital Costs

4. The total capital costs for feasibility purposes are estimated to be \$41.7 million. The detailed capital cost estimates are provided at Exhibit C, Tab 2, Schedule 1. The construction period is assumed to be 7 months. We are seeking a contribution of \$17.7 million. Within approximately 9 months of completion of the installation and commissioning of the distribution line and related infrastructure, the Company will establish the final contribution in aid of construction based on the actual costs incurred to complete such installation. The final contribution in aid of construction so established will be used for purposes of this agreement. This ensures that the project is still feasible.

5. Enbridge Gas Distribution has arranged for financial assurance from Portlands Energy Centre for the investment exposure. This is required to mitigate the risk associated with power plants and to protect the interests of existing ratepayers.

Contract Demand

6. The gas deliveries to the Portlands Energy Centre will be under Rate 125. The contract demand is based on twenty-four times the maximum hourly flow and is established as 2 785 885 m^3.

Summary

7. The feasibility for the Portlands Energy Centre reinforcement project has been prepared based on Enbridge Gas Distribution’s feasibility guidelines pursuant to the Ontario Energy Board’s Decision with Reasons in the Company’s EB-2005-0001 Rate application.

8. The analysis contained at Exhibit E, Tab 1, Schedule 2, shows the project has a Profitability Index ("PI") of 1.0 after customer contribution in the amount of $17.7 million. The project meets the minimum project acceptance threshold PI of 1.0, and thus qualifies for approval by the Ontario Energy Board on the basis of this analysis.

ECONOMIC FEASIBILITY TEST

1. The following economic feasibility evidence has been completed based upon the parameters contained within the feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2005-0001 Rate application.

2. Discounted cash flow ("DCF") analysis is adopted to calculate net present value ("NPV") and profitability index ("PI") for the project. The economic feasibility of the project has been tested using the incremental revenues and costs associated with the project forecast over a 20-year period. This analysis incorporates all incremental capital and operating costs associated with this proposed project. A summary of the inputs and results of the feasibility are included on page 2, while pages 3 to 6 show detailed feasibility parameters and results.

SUMMARY OF INPUTS

Capital Investments

Mains	$36,278,391
Station	$1,041,757
Land	$4,422,000
Total	$41,742,148

Gas Requirements

Under Rate 125	
Daily Contract Demand	2,785,885 m^3

SUMMARY OF RESULTS

Net Present Value (20 years)	$0.0
Profitability Index (20 years)	1.0
Customer Contribution	$17,746,869

APPENDIX 1

Portlands Energy Centre

ECONOMIC FEASIBILITY STUDY

FOR A CUSTOMER REVENUE HORIZON OF 20 YEARS

Portlands Energy Centre
Economic Feasibility - 20 Year Horizon
Parameters and Results

Line No.	Col. 1 Description	Col. 2
	FEASIBILITY PARAMETERS	
1.	Discount Rate	6.15%
2.	CCA Rate	4.00%
3.	Tax Rate	35.00%
4.	Municipal Tax rate	0.60%
5.	Capital Tax Rate	0.29%
6.	Customer Revenue Horizon (Years)	20
7.	Daily Contract Demand , m^3	2,785,885
8.	Annual Distribution Revenues (Dollars)	3,082,919
9.	Annual O&M (Dollars)	2,758
10.	Capital Investment (Dollars)	41,742,148
	Working Capital	
11.	O&M (Lead days)	(33.85)
12.	Commodity (Lag days)	3.75
	FEASIBILITY RESULTS	
13.	Net Present Value (Dollars)	0.0
14.	Profitability Index	1.000
15.	Customer Contribution in Aid of Construction (Dollars)	17,746,869

Portlands Energy Center
Economic Feasibility - 20 year Horizon
DCF Analysis

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Line No.	Description	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
	Discount factors to project outset	0.983	0.928	0.883	0.832	0.784	0.738	0.696	0.655	0.617	0.582
	INCREMENTAL CAPITAL INVESTMENT										
1.	Investment In Mains	36,278,391	-	-	-	-	-	-	-	-	-
2.	Investment in Services	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	1,041,757	-	-	-	-	-	-	-	-	-
4.	Investment in Land	4,422,000	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	(17,746,869)	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	23,995,279	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	256	-	-	-	-	-	-	-	-
8.	Total Investment	23,995,279		-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	23,581,025	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**
	CCA TAX SHIELD										
11.	CCA Tax Shield		150,173	294,339	282,566	271,263	260,413	249,996	239,996	230,397	221,181
12.	PV Of CCA Tax Shield At Project Outset		139,379	259,931	235,078	212,602	192,275	173,892	157,266	142,230	128,631
13.	**ACCUMULATED PV OF CCA TAX SHIELD**		**139,379**	**399,310**	**634,388**	**846,991**	**1,039,266**	**1,213,158**	**1,370,424**	**1,512,654**	**1,641,285**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)										
14.	Gas Distribution Revenue		2,055,279	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919
15.	Gas Costs		-	-	-	-	-	-	-	-	-
16.	O&M Expenses		(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)
17.	Net Operating Cash (Before Taxes)		2,052,521	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161
18.	PV of Net Operating Cash (Before Taxes) At Project Outset		1,904,991	2,720,084	2,562,516	2,414,075	2,274,233	2,142,492	2,018,383	1,901,462	1,791,315
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**		**1,904,991**	**4,625,075**	**7,187,590**	**9,601,665**	**11,875,898**	**14,018,391**	**16,036,773**	**17,938,236**	**19,729,551**
	TAXES										
20.	Income Tax (Before Interest Tax Shield)		(647,021)	(1,011,772)	(1,017,494)	(1,022,783)	(1,022,979)	(1,023,166)	(1,023,346)	(1,023,519)	(1,023,685)
21.	Municipal Tax		(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)
22.	Capital Tax		(59,919)	(45,412)	(29,064)	(13,951)	(13,393)	(12,857)	(12,343)	(11,849)	(11,375)
23.	Total Taxes		(850,911)	(1,201,156)	(1,190,529)	(1,180,706)	(1,180,343)	(1,179,995)	(1,179,661)	(1,179,340)	(1,179,032)
24.	PV of Total Taxes At Project Outset		(789,750)	(1,060,738)	(990,452)	(925,378)	(871,505)	(820,779)	(773,014)	(728,037)	(685,684)
25.	**ACCUMULATED PV OF TOTAL TAXES**		**(789,750)**	**(1,850,488)**	**(2,840,940)**	**(3,766,318)**	**(4,637,823)**	**(5,458,601)**	**(6,231,615)**	**(6,959,652)**	**(7,645,336)**
	ACCUMULATED NPV AND PI										
26.	Net Present Value	(23,581,025)	(22,326,405)	(20,407,129)	(18,599,986)	(16,898,687)	(15,303,683)	(13,808,077)	(12,405,443)	(11,089,787)	(9,855,525)
27.	Profitability Index		0.053	0.135	0.211	0.283	0.351	0.414	0.474	0.530	0.582

Note a) Construction period of 7 months mid-term discounted, July 2007 is the project outset.
Note b) Year 1 Revenue from February 2008 to January 2009.
Note c) Commissioning period - February 2008 to May 2008 inclusive

Portlands Energy Center
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No.	Col. 1 Description	Col. 12 Year 10	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.548	0.516	0.486	0.458	0.432	0.407	0.383	0.361	0.340	0.320	0.302
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains	-	-	-	-	-	-	-	-	-	-	-
2.	Investment in Services	-	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	-	-	-	-	-	-	-	-	-	-	-
4.	Investment in Land	-	-	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	-	-	-	-	-	-	-	-	-	-
8.	Total Investment	-	-	-	-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**	**23,581,025**
	CCA TAX SHIELD											
11.	CCA Tax Shield	212,333	203,840	195,686	187,859	180,345	173,131	166,206	159,557	153,175	147,048	1,476,471
12.	PV Of CCA Tax Shield At Project Outset	116,333	105,210	95,151	86,053	77,826	70,385	63,655	57,569	52,065	47,087	445,400
13.	**ACCUMULATED PV OF CCA TAX SHIELD**	**1,757,617**	**1,862,827**	**1,957,978**	**2,044,031**	**2,121,857**	**2,192,242**	**2,255,897**	**2,313,466**	**2,365,531**	**2,412,618**	**2,858,018**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919	3,082,919
15.	Gas Costs	-	-	-	-	-	-	-	-	-	-	-
16.	O&M Expenses	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)	(2,758)
17.	Net Operating Cash (Before Taxes)	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161	3,080,161
18.	PV of Net Operating Cash (Before Taxes) At Project Outset	1,687,549	1,589,793	1,497,700	1,410,942	1,329,209	1,252,211	1,179,673	1,111,338	1,046,960	986,312	929,178
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	**21,417,100**	**23,006,892**	**24,504,592**	**25,915,534**	**27,244,743**	**28,496,954**	**29,676,627**	**30,787,965**	**31,834,925**	**32,821,238**	**33,750,415**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)	(1,023,844)	(1,023,997)	(1,024,144)	(1,024,285)	(1,024,420)	(1,024,550)	(1,024,675)	(1,024,794)	(1,024,909)	(1,025,019)	(1,025,125)
21.	Municipal Tax	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)	(143,972)
22.	Capital Tax	(10,920)	(10,483)	(10,064)	(9,661)	(9,275)	(8,904)	(8,548)	(8,206)	(7,878)	(7,562)	(78,794)
23.	Total Taxes	(1,178,736)	(1,178,452)	(1,178,179)	(1,177,918)	(1,177,667)	(1,177,425)	(1,177,194)	(1,176,972)	(1,176,758)	(1,176,553)	(1,247,891)
24.	PV of Total Taxes At Project Outset	(645,802)	(608,246)	(572,879)	(539,573)	(508,209)	(478,671)	(450,854)	(424,657)	(399,985)	(376,750)	(376,445)
25.	**ACCUMULATED PV OF TOTAL TAXES**	**(8,291,138)**	**(8,899,383)**	**(9,472,262)**	**(10,011,836)**	**(10,520,045)**	**(10,998,716)**	**(11,449,570)**	**(11,874,228)**	**(12,274,213)**	**(12,650,963)**	**(13,027,408)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value	(8,697,446)	(7,610,689)	(6,590,717)	(5,633,296)	(4,734,470)	(3,890,546)	(3,098,071)	(2,353,822)	(1,654,782)	(998,132)	**0**
27.	Profitability Index	0.631	0.677	0.721	0.761	0.799	0.835	0.869	0.900	0.930	0.958	**1.000**

Note a) Construction period of 7 months mid-term discounted, July 2007 is the pr
Note b) Year 1 Revenue from February 2008 to January 2009.
Note c) Commissioning period - February 2008 to May 2008 inclusive

…continued.

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

Ontario

EB-2008-0065

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 pursuant to Section 90(1) of the Ontario Energy Board Act, 1998, granting leave to construct a natural gas distribution pipeline and related facilities in the City of Thorold in the Regional Municipality of Niagara.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

DECISION AND ORDER

Enbridge Gas Distribution Inc. ("Enbridge" or "EDG") has filed an application with the Board, dated June 27, 2008, under section 90(1) of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c.15, Schedule B, for orders granting leave to construct approximately 2.9 km of Nominal Pipe Size ("NPS") 12 diameter steel high pressure pipeline and a gate station (meter and pressure regulator) in the City of Thorold, in the Regional Municipality of Niagara. The pipeline and related facilities are intended to serve the requirements of natural gas demand for a gas-fired generator currently under construction.

For the reasons set out below, the Board finds that the construction of the proposed pipeline is in the public interest and grants Leave to Construct, subject to certain Conditions of Approval, which are attached to this Decision.

The Proposed Pipeline

The 2.9 km pipeline will be a dedicated line providing natural gas to a 265 MW cogeneration plant proposed by Northland Power Inc., Thorold Cogen L.P. ("Thorold Cogen facility"), in Thorold being constructed at the Abitibi Plant where both heat and electricity will be produced.

A map showing the location of the proposed pipeline and ancillary facility is attached as Appendix A. The proposed pipeline will originate at the TransCanada Pipeline ("TCPL") where it crosses Thorold Townline Road. At that location, Enbridge proposes to construct a gate station to reduce the TCPL line pressure to less than 4500 kPa (653 psi) and to measure the gas volumes to the Thorold Cogen station. Enbridge's proposed line will proceed north along the road allowance of Thorold Townline Road from the intersection with TCPL for approximately 0.6 km to Beaversdams Road. The pipeline will then proceed west along Beaversdams Road for 0.8 km to Davis Road (Highway 58) and Niagara Falls Road. The pipeline will follow Niagara Falls Road west for approximately 1.2 km to Allanburg Road where it will proceed north on Allanburg Road for 0.2 km to the route end point located at the proposed Thorold Cogen facility.

The Proceeding

The Board issued the Notice of Application on August 1, 2008, which was published and served by EGD as directed. Intervenor requests were received from Walker Community Development Corporation, Thorold Cogen L.P. and Hydro One Networks Inc. All requests for intervention were approved. No observer or letters of comment were filed. The Board proceeded by way of a written hearing. No interrogatories or submissions were filed by the intervenors

On September 4, 2008, Board Staff, through written interrogatories, requested clarification of certain aspects of the pre-filed evidence and additional information. On

September 23, 2008, EGD responded to the interrogatories, which concluded the discovery phase of the proceeding.
This is an application under section 90 of the Act, seeking a Leave to Construct Order. Section 96 of the Act provides that the Board shall make an Order granting leave if the Board finds that "the construction, expansion or reinforcement of the proposed work is in the public interest". When determining whether a project is in the public interest, the Board typically examines the need for the project, the economics of the project, the environmental impact, the impact on landowners and consultation with Aboriginal Peoples. Each of these factors will be considered in turn.

The Need for the Project

The proposed pipeline and related facilities are intended to deliver gas to the proposed Thorold Cogen facility.

The Thorold Cogen facility is a 265 MW combined heat and power ("CHP") facility that is natural-gas fired. The waste heat from the turbine will be used to produce steam, some of which will be piped over to and consumed by the Abitibi-Consolidated paper mill that is located on the same property. Thorold Cogen has entered into a 20-year agreement with the Ontario Power Authority ("OPA") to supply electricity to the province. This agreement was the result of an OPA-administered competitive Request for Proposal ("RFP") process as per an Ontario Ministry of Energy directive. The directive was in response to critical needs for new clean, efficient and reliable electricity supply in the province. Thorold Cogen was selected to develop a CHP facility through the RFP process.

EGD states, and the Board accepts, that the timely development of the facilities required to deliver natural gas to the Thorold Cogen facility is critical to achieving these reliability and efficiency objectives. Gas will be required for commissioning during the third quarter of 2009 to prepare for commercial operation in the first quarter of 2010.

The Proposed Pipeline's Design

According to EGD's evidence, the design and pipe specifications, installation and testing of the proposed pipeline adhere to the requirements of Ontario Regulation 210/01 under the *Technical Standards and Safety Act*, Oil and Gas Pipeline Systems and the CSA Z662-03 Oil and Gas Pipeline Systems code.

The Board is satisfied that the evidence establishes that the pipeline design and specifications are acceptable.

Environmental Assessment and Routing

EGD retained Stantec Consulting Limited ("Stantec") to undertake an environmental assessment, evaluate alternatives and advise on the selection of a preferred route. The environmental assessment was carried out in accordance with the Board's "Environmental Guidelines for the Location, Construction and Operation of Hydrocarbon Pipelines and Facilities in Ontario (May 2003)" (the "Board's Environmental Guidelines"). The results of the assessment are documented in the report entitled "Environmental Report: Pipeline to serve the proposed Thorold Cogen L.P." dated April, 2008 (the "Stantec Report"), which was filed in this proceeding.

As part of the environmental assessment process, Stantec undertook consultation with government agencies and the public. Public meetings were held on May 16, 2007, June 26, 2007 and March 18, 2008 to inform the public of the project and to solicit input. The Stantec Report included details of the public consultation undertaken. No major concerns were identified.

In accordance with the Board's Environmental Guidelines, the Stantec Report was reviewed by the Ontario Pipeline Coordination Committee ("OPCC"). There are no outstanding concerns related to the OPCC review.

Stantec assessed and rated five route alternatives using routing criteria and consideration of proposed mitigation measures. The Stantec Report concluded that the preferred route selected is the shortest in length and has the least potential for encountering archaeological resources. The Report states that the mitigating measures proposed comply with accepted industry practice and EGD's construction manual, and that the net residual environmental effects do not constitute a significant environmental effect.

EGD confirms that all permits and approvals will be secured prior to the construction of the pipeline.

The Board accepts EGD's evidence regarding the environmental assessment of the proposed pipeline, and finds that the proposed mitigation and monitoring activities are acceptable and address the environmental concerns. The Board also accepts that the proposed project is the best alternative.

Economics of the Project

The total estimated cost for the Thorold Cogen Pipeline project is $6,397,224. The economic feasibility of the project was measured in accordance with the Board's approved procedures as established in EBO 188[1]. The feasibility analysis for the project was based upon a 20-year customer revenue horizon and has been prepared based on EGD's feasibility guidelines pursuant to the Board's Decision with Reasons in EGD's EB-2006-0034 rate application. This analysis indicated that the proposed facilities have a Net Present Value ("NPV") of $0 and a Profitability Index ("PI") of 1.00. A PI at or above 1.0 indicates that the project is economic for EGD. Enbridge's Rate-125 will recover the revenue requirement through monthly demand charges.

The Board accepts EGD's evidence and finds that the project is economically feasible under the proposed feasibility analysis.

Land Issues and Form of Easement

Section 97 of the Act provides that a leave to construct will not be granted until the applicant has satisfied the Board that it has offered or will offer to each owner of land

[1] [The Consumers Gas Company Ltd, Union Gas Limited and Centra Gas Ontario Inc., Natural Gas System Expansion, Report of the Board, EBO 188, (January 30, 1998)]

affected by the approved route or location an agreement in a form approved by the Board.

EGD has indicated that the proposed pipeline is to be located entirely within existing road allowances. As such, EGD does not anticipate the need to obtain either temporary or permanent land rights. However, EGD has filed with the Board a form of easement agreement that it will offer to landowners in the event that requirement for easements change.

EGD notes that two acres of property are required for the Gate Station facilities. There are three potential locations identified for the Gate Station. Negotiations are continuing with the landowners to finalize the site for the Gate Station.

The Board approves the form of easement which has been filed by EGD.

Aboriginal Consultation Conducted by Enbridge

EGD, through the Stantec Report, advised that there were no known First Nation reserves or lands that are currently used along the proposed pipeline route for traditional or cultural purposes.

Stantec initiated consultation with the Indian and Northern Affairs Canada ("INAC") to ensure the status of lands within the Study area did not contain First Nation reserves or lands. A response from INAC's Specific Claims Branch was received on July 19, 2007, indicating that there are no land claims in the Study Area that INAC is aware of.

The Board is satisfied that EGD has conducted a proper search and that no Aboriginal groups will be adversely affected by the proposed project.

Orders Granted

For the reasons indicated, the Board finds the pipeline project proposed by EGD in this proceeding is in the public interest and grants an Order for Leave to Construct subject to the Conditions of Approval as set out in Appendix B.

THE BOARD ORDERS THAT:

1. Enbridge Gas Distribution Inc. is granted leave, pursuant to subsection 90 (1) of the Act, to construct approximately 2.9 kilometres of NPS 12 in the City of Thorold, the Regional Municipality of Niagara for the purpose of supplying natural gas to the Thorold Cogen L.P. facility, subject to the Conditions of Approval set forth in Appendix B.

2. Enbridge Gas Distribution Inc. shall pay the Board’s costs incidental to this proceeding upon receipt of the Board’s invoice.

DATED at Toronto October 28, 2008

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

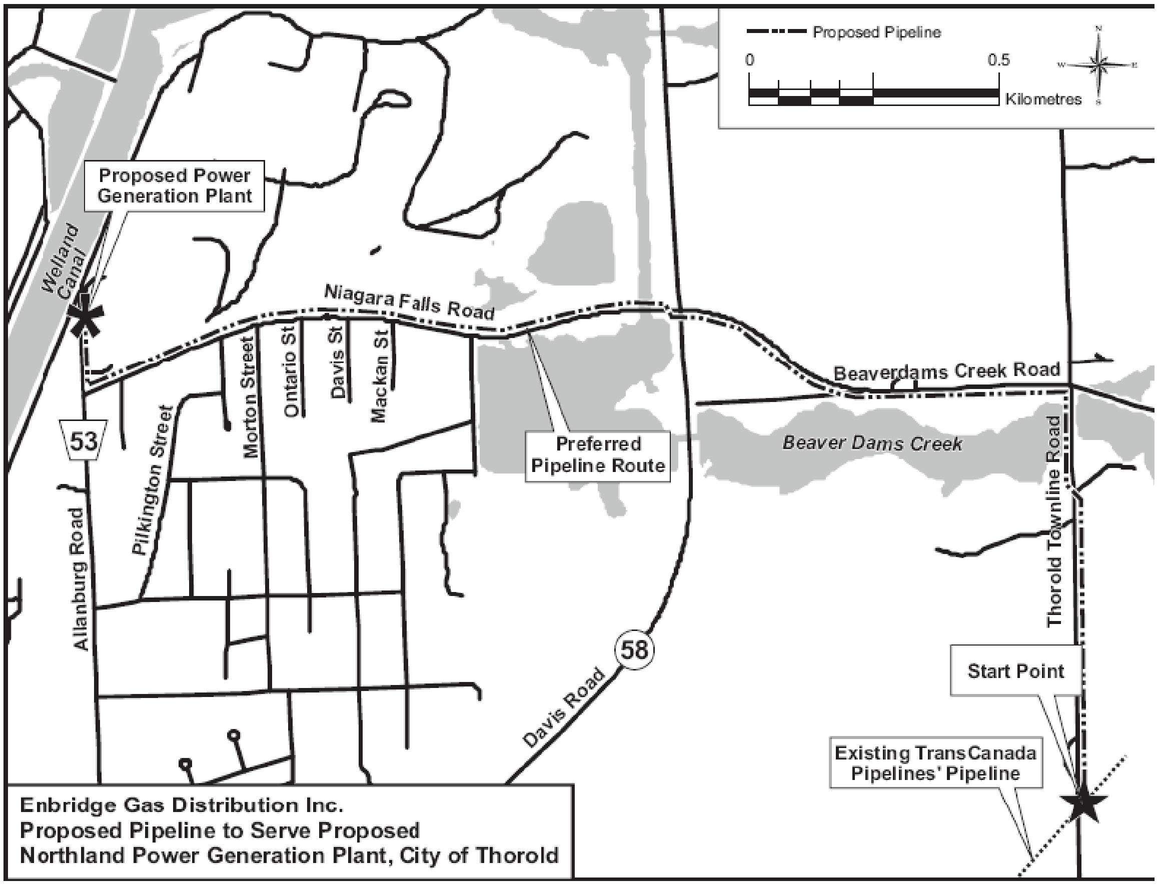
APPENDIX A

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2008-0065

DATED October 28, 2008

MAP OF THE PIPELINE ROUTE


Proposed Pipeline
0
0.5
Kilometres
Proposed Power Generation Plant
Welland Canal
Niagara Falls Road
Beaverdams Creek Road
Morton Street
Ontario St
Davis St
Mackan St
Pilkington Street
53
Allanburg Road
Preferred Pipeline Route
Beaver Dams Creek
Thorold Townline Road
58
Davis Road
Start Point
Existing TransCanada Pipelines' Pipeline
Enbridge Gas Distribution Inc.
Proposed Pipeline to Serve Proposed
Northland Power Generation Plant, City of Thorold

APPENDIX B

TO BOARD DECISION AND ORDER

IN THE MATTER OF EB-2008-0065

DATED October 28, 2008

CONDITIONS OF APPROVAL

Conditions of Approval

Leave to Construct

1 General Requirements

1.1 Enbridge Gas Distribution Inc. ("Enbridge") shall construct the facilities and restore the land in accordance with its application and the evidence filed in EB-2008-0065, except as modified by this Order and these Conditions of Approval.

1.2 Unless otherwise ordered by the Board, authorization for Leave to Construct shall terminate December 31, 2009, unless construction has commenced prior to then.

1.3 Except as modified by this Order, Enbridge shall implement all the recommendations of the Environmental Report filed in the pre-filed evidence, and all the recommendations and directives identified by the Ontario Pipeline Coordinating Committee ("OPCC") review.

1.4 Enbridge shall advise the Board's designated representative of any proposed material change in construction or restoration procedures and, except in an emergency, Enbridge shall not make such change without prior approval of the Board or its designated representative. In the event of an emergency, the Board shall be informed immediately after the fact.

2 Project and Communications Requirements

2.1 The Board's designated representative for the purpose of these Conditions of Approval shall be the Manager, Facilities Applications.

2.2 Enbridge shall designate a person as project engineer and shall provide the name of the individual to the Board's designated representative. The project engineer will be responsible for the fulfilment of the Conditions of Approval on the construction site. Enbridge shall provide a copy of the Order and Conditions of Approval to the project engineer, within seven days of the Board's Order being issued.

2.3 Enbridge shall give the Board's designated representative and the Chair of the OPCC ten days written notice in advance of the commencement of the construction.

2.4 Enbridge shall furnish the Board's designated representative with all reasonable assistance for ascertaining whether the work is being or has been performed in accordance with the Board's Order.

2.5 Enbridge shall file with the Board’s designated representative notice of the date on which the installed pipelines were tested, within one month after the final test date.

2.6 Enbridge shall furnish the Board’s designated representative with five copies of written confirmation of the completion of construction. A copy of the confirmation shall be provided to the Chair of the OPCC.

3 Monitoring and Reporting Requirements

3.1 Both during and after construction, Enbridge shall monitor the impacts of construction, and shall file four copies of both an interim and a final monitoring report with the Board. The interim monitoring report shall be filed within six months of the in-service date, and the final monitoring report shall be filed within fifteen months of the in-service date. Enbridge shall attach a log of all complaints that have been received to the interim and final monitoring reports. The log shall record the times of all complaints received, the substance of each complaint, the actions taken in response, and the reasons underlying such actions.

3.2 The interim monitoring report shall confirm Enbridge’s adherence to Condition 1.1 and shall include a description of the impacts noted during construction and the actions taken or to be taken to prevent or mitigate the long-term effects of the impacts of construction. This report shall describe any outstanding concerns identified during construction.

3.3 The final monitoring report shall describe the condition of any rehabilitated land and the effectiveness of any mitigation measures undertaken. The results of the monitoring programs and analysis shall be included and recommendations made as appropriate. Any deficiency in compliance with any of the Conditions of Approval shall be explained.

4 Easement Agreements

4.1 Enbridge shall offer the form of agreement approved by the Board to each landowner, as may be required, along the route of the proposed work.

5 Other Approvals and Agreements

5.1 Enbridge shall obtain all other approvals, permits, licences, and certificates required to construct, operate and maintain the proposed project, shall provide a list thereof, and shall provide copies of all such written approvals, permits, licences, and certificates upon the Board's request.

5.2 Enbridge shall not, without prior approval of the Board, consent to any alteration or amendment to the Gas Delivery Agreement dated and executed on August 15, 2007, where such alteration or amendment has or may have any material impact on Enbridge's ratepayers.

5.3 Enbridge shall file with the Board, a copy of Thorold Cogen L.P.'s irrevocable bank letter of credit to Enbridge for an amount not less than cost estimate of the applied-for facilities; this filing shall take place no later than 14 days after the start of construction.

ECONOMIC FEASIBILITY

METHODOLOGY

1. The economic feasibility of the project has been determined using a methodology that adheres to the "Ontario Energy Board Guidelines for Assessing and Reporting on Natural Gas System Expansion in Ontario" and the EBO 188 "Report of the Board" dated January 30, 1998.

2. The economic feasibility of the project has been calculated by discounting incremental cash flows over the 20-year customer revenue horizon. The resulting Net Present Value ("NPV") represents both the economic feasibility of the project from the utility's perspective and its effect within the Rolling Project Portfolio. An NPV greater than zero indicated that the project will make a positive contribution to the Rolling Project Portfolio and be feasible from a utility cash flow perspective. Exhibit E, Tab 1, Schedule 2 details the NPV for the project.

KEY ASSUMPTIONS

Customer Revenue Horizon

3. Feasibility analysis for the project was based upon a 20-year customer revenue horizon. The first year revenue is calculated based on nine months as the Customer has requested a three month commissioning period. /u

Capital Costs

4. The project capital costs are estimated to be $6,397,224. The detailed capital cost estimates are provided at Exhibit C, Tab 2, Schedule 1. The construction period is assumed to be 5 months. As part of the requirements under the GDA, Thorold Cogen has provided financial assurances in the form of an irrevocable letter of credit. This will be in addition to the requirements under the Gas Transportation Agreement. This is required to

mitigate the risk associated with power plants and to protect the interests of existing ratepayers.

Contract Demand

5. The gas deliveries to the Thorold Cogen will be under Rate 125. For this dedicated service line, the contract demand is established by calculating the annual revenues required under Rate 125 to completely recover the capital invested in the chosen customer horizon period. Any overruns in gas consumption lead to additional revenues calculated at the unitized rate of Rate 125.

6. The 'Billing Contract Demand' is estimated to be 768,449 m^3. Within nine (9) months of completion of the installation and commissioning of the distribution line and related infrastructure which Enbridge has determined is required to be installed to service the Terminal Location, Enbridge will establish the final 'Billing Contract Demand' based on the actual costs incurred to complete such installation, and shall notify the customer of such final 'Billing Contract Demand'. The final 'Billing Contract Demand' so established will be used for purposes of this Agreement for the duration of the Term. This ensures that the project is still feasible. /u

Summary

7. The feasibility for the Thorold Cogen project has been prepared based on Enbridge's feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2007-0615 Application.

8. The analysis contained at Exhibit E, Tab 1, Schedule 2, shows the project has a PI of 1.0.

ECONOMIC FEASIBILITY TEST

1. The following economic feasibility evidence has been completed based upon the parameters contained within the feasibility guidelines pursuant to the Ontario Energy Board's Decision with Reasons in the Company's EB-2007-0615 Application.

2. Discounted cash flow ("DCF") analysis is adopted to calculate net present value ("NPV") and profitability index ("PI") for the project. The economic feasibility of the project has been tested using the incremental revenues and costs associated with the project forecast over a 20-year period. This analysis incorporates all incremental capital and operating costs associated with this proposed project. A summary of the inputs and results of the feasibility are included on page 2, while pages 3 to 6 show detailed feasibility parameters and results.

SUMMARY OF INPUTS

Capital Investments	
Mains	\$3,599,872
Station	\$2,326,802
Land	\$470,550
Total	\$6,397,224

Gas Requirements		
Under Rate 125		
Billing Contract Demand	768,449m^3	/u

SUMMARY OF RESULTS

Net Present Value (20 years)	\$0.0
Profitability Index (20 years)	1.0
Customer Contribution	\$0.0

APPENDIX 1

Thorold Cogen L.P.

ECONOMIC FEASIBILITY STUDY

FOR A CUSTOMER REVENUE HORIZON OF 20 YEARS

Thorold Cogen L.P.
Economic Feasibility - 20 Year Horizon
Parameters and Results

Line No.	Col. 1 Description	Col. 2	
	FEASIBILITY PARAMETERS		
1.	Discount Rate	5.98%	
2.	CCA Rate	6.00%	
3.	Tax Rate	36.12%	
4.	Municipal Tax rate	0.60%	
5.	Capital Tax Rate	0.23%	
6.	Customer Revenue Horizon (Years)	20	
7.	Billing Contract Demand , m^3	768,449	/u
8.	Annual Distribution Revenues (Dollars)	836,820	
9.	Annual O&M (Dollars)	56,000	
10.	Capital Investment (Dollars)	6,397,224	
	Working Capital		
11.	O&M (Lead days)	(26.90)	
12.	Commodity (Lag days)	4.10	
	FEASIBILITY RESULTS		
13.	Net Present Value (Dollars)	0.0	
14.	Profitability Index	1.000	
15.	Customer Contribution in Aid of Construction (Dollars)	-	

Thorold Cogen L.P.
Economic Feasibility - 20 year Horizon
DCF Analysis

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
Line No	Description	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9
	Discount factors to project outset	0.988	0.939	0.895	0.844	0.796	0.751	0.709	0.669	0.631	0.596
	INCREMENTAL CAPITAL INVESTMENT										
1.	Investment In Mains	3,599,872	-	-	-	-	-	-	-	-	-
2	Investment in Services	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	2,326,802	-	-	-	-	-	-	-	-	-
4.	Investment in Land	470,550	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	6,397,224	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	4,127	-	-	-	-	-	-	-	-
8.	Total Investment	6,397,224		-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	6,316,364	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**
	CCA TAX SHIELD										
11.	CCA Tax Shield		64,221	124,590	117,114	110,087	103,482	97,273	91,437	85,951	80,794
12.	PV Of CCA Tax Shield At Project Outset		60,303	111,457	98,855	87,677	77,764	68,971	61,172	54,256	48,121
13.	**ACCUMULATED PV OF CCA TAX SHIELD**		**60,303**	**171,760**	**270,615**	**358,292**	**436,056**	**505,027**	**566,199**	**620,454**	**668,575**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)										
14.	Gas Distribution Revenue		627,615	836,820	836,820	836.820	836,820	836,820	836,820	836,820	836,820
15.	Gas Costs		-	-	-	-	-	-	-	-	-
16.	O&M Expenses		(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)
17.	Net Operating Cash (Before Taxes)		571,615	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820
18.	PV of Net Operating Cash (Before Taxes) At Project Outset		536,738	698,517	659,081	621,871	586,762	553,635	522,378	492,886	465,059
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**		**536,738**	**1,235,255**	**1,894,336**	**2,516,207**	**3,102,969**	**3,656,603**	**4,178,982**	**4,671,868**	**5,136,927**
	TAXES										
20.	Income Tax (Before Interest Tax Shield)		(187,931)	(263,776)	(264,040)	(264,288)	(264,520)	(264,739)	(264,945)	(265,138)	(265,320)
21.	Municipal Tax		(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)
22.	Capital Tax		(12,935)	(12,159)	(11,429)	(10,744)	(10,099)	(9,493)	(8,923)	(8,388)	(7,885)
23.	Total Taxes		(239,249)	(314,319)	(313,853)	(313,414)	(313,003)	(312,616)	(312,252)	(311,910)	(311,588)
24.	PV of Total Taxes At Project Outset		(224,652)	(281,188)	(264,919)	(249,614)	(235,212)	(221,658)	(208,900)	(196,890)	(185,583)
25.	**ACCUMULATED PV OF TOTAL TAXES**		**(224,652)**	**(505,839)**	**(770,758)**	**(1,020,372)**	**(1,255,584)**	**(1,477,242)**	**(1,686,142)**	**(1,883,032)**	**(2,068,615)**
	ACCUMULATED NPV AND PI										
26.	Net Present Value	(6,316,364)	(5,943,975)	(5,415,189)	(4,922,172)	(4.462.238)	(4,032,924)	(3,631,976)	(3,257,326)	(2,907,075)	(2,579,478)
27.	Profitability Index		0.059	0.143	0.221	0.294	0.362	0.425	0.484	0.540	0.592

Note a) Construction period of 5 months mid-term discounted. April 2009 is the project outset.
Note b) Year 1 Revenue from September 2009 to August 2010.
Note c) Commissioning period - September 2009 to November 2009 inclusive

Thorold Cogen L.P.
Economic Feasibility - 20 year Horizon
DCF Analysis

Line No	Col 1 Description	Col. 12 Year 10	Col. 13 Year 11	Col. 14 Year 12	Col. 15 Year 13	Col. 16 Year 14	Col. 17 Year 15	Col. 18 Year 16	Col. 19 Year 17	Col. 20 Year 18	Col. 21 Year 19	Col. 22 Year 20
	Discount factors to project outset	0.562	0.530	0.500	0.472	0.445	0.420	0.397	0.374	0.353	0.333	0.314
	INCREMENTAL CAPITAL INVESTMENT											
1.	Investment In Mains	-	-	-	-	-	-	-	-	-	-	-
2.	Investment in Services	-	-	-	-	-	-	-	-	-	-	-
3.	Investment in Stations	-	-	-	-	-	-	-	-	-	-	-
4.	Investment in Land	-	-	-	-	-	-	-	-	-	-	-
5.	Contribution In Aid of Construction	-	-	-	-	-	-	-	-	-	-	-
6.	Net Investment Capital	-	-	-	-	-	-	-	-	-	-	-
7.	Working Capital	-	-	-	-	-	-	-	-	-	-	-
8.	Total Investment	-	-	-	-	-	-	-	-	-	-	-
9.	PV Of Total Investment At Project Outset	-	-	-	-	-	-	-	-	-	-	-
10.	**ACCUMULATED PV OF TOTAL INVESTMENT**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**	**6,316,364**
	CCA TAX SHIELD											
11.	CCA Tax Shield	75,946	71,389	67,106	63,079	59,295	55,737	52,393	49,249	46,294	43,517	361,773
12.	PV Of CCA Tax Shield At Project Outset	42,680	37,854	33,574	29,778	26,411	23,424	20,776	18,427	16,343	14,495	113,703
13.	**ACCUMULATED PV OF CCA TAX SHIELD**	**711,255**	**749,109**	**782,683**	**812,461**	**838,872**	**862,296**	**883,072**	**901,499**	**917,842**	**932,337**	**1,046,040**
	INCREMENTAL OPERATING CASH FLOWS (BEFORE TAXES)											
14.	Gas Distribution Revenue	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820	836,820
15.	Gas Costs	-	-	-	-	-	-	-	-	-	-	-
16.	O&M Expenses	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)	(56,000)
17.	Net Operating Cash (Before Taxes)	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820	780,820
18.	PV of Net Operating Cash (Before Taxes) At Project Outset	438,803	414,029	390,654	368,599	347,789	328,154	309,627	292,146	275,652	260,090	245,406
19.	**ACCUMULATED PV OF NET OPERATING CASH (BEFORE TAXES)**	**5,575,730**	**5,989,759**	**6,380,413**	**6,749,012**	**7,096,801**	**7,424,955**	**7,734,582**	**8,026,728**	**8,302,381**	**8,562,471**	**8,807,876**
	TAXES											
20.	Income Tax (Before Interest Tax Shield)	(265,491)	(265,652)	(265,803)	(265,945)	(266,078)	(266,203)	(266,321)	(266,432)	(266,536)	(266,634)	(266,726)
21.	Municipal Tax	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)	(38,383)
22.	Capital Tax	(7,412)	(6,967)	(6,549)	(6,156)	(5,787)	(5,439)	(5,113)	(4,806)	(4,518)	(4,247)	(37,305)
23.	Total Taxes	(311,286)	(311,002)	(310,735)	(310,484)	(310,248)	(310,026)	(309,818)	(309,622)	(309,438)	(309,264)	(342,414)
24.	PV of Total Taxes At Project Outset	(174,936)	(164,909)	(155,465)	(146,569)	(138,189)	(130,294)	(122,855)	(115,846)	(109,241)	(103,015)	(107,618)
25.	**ACCUMULATED PV OF TOTAL TAXES**	**(2,243,551)**	**(2,408,460)**	**(2,563,924)**	**(2,710,493)**	**(2,848,682)**	**(2,978,977)**	**(3,101,832)**	**(3,217,678)**	**(3,326,918)**	**(3,429,934)**	**(3,537,552)**
	ACCUMULATED NPV AND PI											
26.	Net Present Value	(2,272,931)	(1,985,956)	(1,717,192)	(1,465,384)	(1,229,374)	(1,008,090)	(800,542)	(605,815)	(423,060)	(251,490)	**(0)**
27.	Profitability Index	0.640	0.686	0.728	0.768	0.805	0.840	0.873	0.904	0.933	0.960	**1.000**

Note a) Construction period of 5 months mid-term discounted, April 2009 is the project outset.
Note b) Year 1 Revenue from September 2009 to August 2010

...continued.

Note c) Commissioning period - September 2009 to November 2009 inclusive.

CME INTERROGATORY #4

INTERROGATORY

Issue 7 – Y Factor – DSM Program

Reference: Exhibit B, Tab 1, Sch. 2, page 1, column 3, line 20
Exhibit B, Tab 2, Sch. 2, pages 1 to 4

The evidence indicates that EGD is seeking a 2010 DSM Budget that simply escalates the 2009 Board approved Budget by 5%. Please provide the following information:

(a) What is the rationale and justification for the 5% escalation?

RESPONSE

a) The 5% escalator is being used in compliance with the Board's direction in its letter of April 14, 2009: "It is expected that the 2010 plans will be filed under the current DSM framework, including increases based on the established budget escalators."

These "established" escalators are documented in the Board's EB-2006-0021 Decision with Reasons, page 23.

The DSM Y factor amount of $26.7 million was approved by the Board in EB-2009-0156, Phases I and II.

Witnesses:	I. Chan	K. Culbert
	A. Kacicnik	T. Ladanyi
	A. Mandyam	P. Squires
	D. Small	

CME INTERROGATORY #5

INTERROGATORY

Issue 9 – Y Factor – CIS Costs and Customer Care

Reference: Exhibit B, Tab 1, Sch. 2, page 1, column 3, line 21
Exhibit B, Tab 2, Sch. 5, page 1

There is an on-going CIS Consultative to deal with EGD's implementation of its new CIS. A final meeting of the Steering Committee of that Consultative, at which EGD is expected to provide some final cost and rate impact information, has been indefinitely postponed by EGD. Please provide the following information:

(a) Are there any costs included in the CIS Y Factor for 2010 that are the subject matter of the yet to be made presentation to the Steering Committee of the CIS Consultative? If so, what are these cost items?

(b) Please provide a current status report on the implementation of the new CIS and an indication of when the final meeting of the Steering Committee of the CIS Consultative is likely to be re-scheduled.

RESPONSE

a) For rate making purposes established within the Company's IR methodology the $95.7 million CIS / Customer Care Y Factor included for 2010 is the amount as per the CIS / Customer Care Settlement Agreement approved by the Board in the EB-2007-0615 Decision and Rate Order, Appendix A, page 1. All costs relative to the CIS Customer Care Settlement agreement are presumed to be subject matter for presentation and discussion at the next consultative meeting.

b) The new CIS was implemented and became operational in September 2009. The next meeting of the CIS Steering Committee is likely to be re-scheduled within an available time period during February 2010 or at the earliest opportunity for all consultative participants.

Witnesses: K. Culbert
M. Mees

CME INTERROGATORY #6

INTERROGATORY

Issue 10 – Z Factor – Pension Funding

Reference: Exhibit B, Tab 1, Sch. 2, page 1, column 3, line 25
Exhibit B, Tab 3, Sch. 1, pages 1 and 5

The evidence indicates that the surplus in prior years "precluded" EGD from making contributions to its pension plans and that the Z Factor claim for this item ranges between $3.0M and $18.9M. Please provide the following information:

(a) Notwithstanding an inability to recover amounts from ratepayers when its pension plans are in a surplus situation, what is it that "precludes" EGD from making contributions to these plans? Does its management not have a discretion to continue to fund the plans, even though they are in a surplus condition?

(b) Now that the 2009 year is over, what is the actual amount of the payment, if any, EGD must make to the plans?

(c) Please provide the 2010 distribution revenue requirement impact and the rate impacts of a 2010 pension plan payment Z Factor of $3M.

RESPONSE

a) The *Income Tax Act ("ITA")* limits contributions permitted to be made to registered pension plans in Canada (see extract below). Plans that make contributions in excess of these limits risk having their registered tax status revoked. Limits on employer pension contributions can be found in s. 147 of the *ITA*. An excerpt from the most recently filed valuation as at December 31, 2006 which illustrates this limit is given below.

> In accordance with Section 147(2) of the *ITA*, the plan would not retain its registered status if EGD made a contribution while the funding excess ($206,848,000 as at December 31, 2006) exceeded the lesser of:

Witnesses: I. Chan, K. Culbert, J. Haberbusch, A. Kacicnik, N. Kishinchandani, T. Ladanyi, D. Small

- 20% of the going-concern actuarial liability ($122,873,000); and
- the greater of:
  - o 10% of the going-concern actuarial liability ($61,437,000); and
  - o two years of total current service cost ($28,716,000).

Since the funding excess exceeded the maximum allowed under Section 147(2) of the *ITA*, no contribution to the plan by EGD was permitted before funding excess was reduced to less than $61,437,000, or else the plan's registered status would have been revoked.

Extract from the Income Tax Act

ITA Section 147, Subsection (2) *(excerpt only)*

(2) For the purposes of subsection (1), a contribution made by an employer to a registered pension plan in respect of the defined benefit provisions of the plan is an eligible contribution if it is a prescribed contribution or if it complies with prescribed conditions and is made pursuant to a recommendation by an actuary in whose opinion the contribution is required to be made so that the plan will have sufficient assets to pay benefits under the defined benefit provisions of the plan, as registered, in respect of the employees and former employees of the employer, where:

…

(d) a recommendation with respect to the contributions required to be made by an employer in respect of the defined benefit provisions of a pension plan may be prepared without regard to such portion of the assets of the plan apportioned to the employer in respect of the employer's employees and former employees as does not exceed the least of

(i) the amount of actuarial surplus in respect of the employer,

(ii) 20% of the amount of actuarial liabilities apportioned to the employer in respect of the employer's employees and former employees, and

(iii) the greater of

(A) 2 times the estimated amount of current service contributions that would, if there were no actuarial surplus, be required to be made by the employer and the employer's employees for the 12 months immediately following the effective date of the actuarial valuation on which the recommendation is based, and

(B) the amount that would be determined under subparagraph (ii) if the reference therein to "20%" were read as a reference to "10%".

Witnesses:	I. Chan	K. Culbert
	J. Haberbusch	A. Kacicnik
	N. Kishinchandani	T. Ladanyi
	D. Small	

b. The actual amount of payment that EGD must make to the plans will be determined based on the results of valuation conducted as at December 31, 2009. These results will be available from the actuary no earlier than April 2009.

c. A reduction of the Pension Funding Z-factor from $18.9 million to $3.0 million would reduce the proposed 2010 distribution revenue requirement by $15.9 million from $1,003.3 million to $987.4 million. This would reduce the total revenue requirement inclusive of gas costs to operations from $2,456.8 million to $2,440.9 million.

The recovery of a total revenue requirement of $2,440.9 million would result in the following approximate average rate impacts by rate class:

Rate Class	T-Service Rate Impact
1	0.5%
6	0.3%
9	0.7%
100	0.4%
110	0.4%
115	0.3%
135	0.3%
145	0.3%
170	0.4%
200	0.2%
	Delivery Rate Impact
125	0.4%
300	0.4%

For comparison, the proposed average rate impacts resulting from the Company's application (as updated) are set out at Exhibit B, Tab 4, Schedule 1, page 3.

Witnesses: I. Chan, J. Haberbusch, N. Kishinchandani, D. Small, K. Culbert, A. Kacicnik, T. Ladanyi

CME INTERROGATORY #7

INTERROGATORY

Issue 11 – Z Factor – Crossbores/Service Laterals

Reference: Exhibit B, Tab 1, Sch. 2, column 3, line 26
Exhibit B, Tab 2, Sch. 2, page 1

EGD is seeking a 2010 Z Factor on account of this item in the amount of $3.6M. Please provide the following information:

(a) The 2010 distribution revenue requirement and rate impacts of a disallowance of this Z Factor claim.

RESPONSE

A disallowance of the Crossbore/Service Lateral Z-factor would reduce the proposed 2010 distribution revenue requirement by $3.6 million from $1,003.3 million to $999.7 million. This would reduce the total revenue requirement inclusive of gas costs to operations from $2,456.8 million to $2,453.2 million.

The recovery of a total revenue requirement of $2,453.2 million would result in the following approximate average rate impacts by rate class:

Table 1: 2010 Proposed Average Rate Impacts

Rate Class	T-Service Rate Impact
1	1.4%
6	1.0%
9	1.0%
100	0.8%
110	0.8%
115	0.6%
135	0.8%
145	0.8%
170	0.8%
200	0.6%
	Delivery Rate Impact
125	1.0%
300	1.0%

Witnesses: J. Collier
K. Culbert
A. Kacicnik
M. Suarez

For comparison, the proposed average rate impacts resulting from the Company's application (as updated) are set out at Exhibit B, Tab 4, Schedule 1, page 3.

Witnesses: J. Collier
K. Culbert
A. Kacicnik
M. Suarez

CME INTERROGATORY #8

INTERROGATORY

Issues 12, 13, 14 – 2010 Deferral and Variance Accounts

Reference: Exhibit B, Tab 7, Sch. 1, page 1
Exhibit C, Tab 1, Sch. 1

With respect to the information in Exhibit B, Tab 7, Schedule 1, please provide particulars of each and every item recorded in each of the deferral accounts listed in lines 8 to 21 inclusive.

RESPONSE

As indicated in response to SEC Interrogatory #7 at Exhibit I, Tab 6, Schedule 7 and VECC Interrogatory #6 at Exhibit I, Tab 7, Schedule 6, EGD will be requesting the review and approval for clearance of amounts in the 2009 group of accounts, which have not yet received Board approval for future clearance, in the 2009 ESM and Deferral and Variance Account review application due to be filed in early March 2010. The Company will respond to questions of the 2009 accounts in that proceeding.

There are some deferral and variance accounts and amounts listed which have already been reviewed in past proceedings and have received Board Approval for future clearance. For an explanation of which accounts are already approved for clearance in April/May 2010 and in July 2010, please see Exhibit B, Tab 7, Schedule 1, pages 1 & 2, as updated 2010-01-22.

Witnesses: K. Culbert
A. Kacicnik
D. Small

SCHOOL ENERGY COALITION INTERROGATORY #1

INTERROGATORY

[Ex. A/3/1, p. 1] Please confirm that the Applicant still proposes that new rates be effective January 1, 2010. Please advise the methodology the Applicant proposes to use, if any, to recover any revenue shortfall, or refund any revenue overcollection, if the actual date the rates are changed is later than January 1, 2010. Please provide rate schedules and rate impacts based on a the Application as currently before the Board, but an implementation date of May 1, 2010 (or a later date if the date is relevant to the Applicant's proposal), reflecting the Applicant's proposed recovery methodology.

RESPONSE

Yes, the Company's proposal is that the new 2010 rates be effective January 1, 2010.

The Company also proposes to recover any revenue shortfall or refund any revenue over-collection using Revenue Adjustment Rider (Rider E).

The process of implementing new rates, including Rider E derivation, would be as described below. This is consistent with the approach the Company proposed and the Board approved in test years 2005 – 2009 where in each year the new rates were implemented after the January 1st effective date.

Interim Rates

In its Procedural Order No. 1 the Ontario Energy Board (the Board) ordered that Enbridge's rates in effect as at December 31, 2009 shall become interim rates effective January 1, 2010.

Timing of Implementation of Final 2010 Rates into Billing

From customer communication and billing perspectives, the Company prefers to implement new rates into billing through the established rate change process, that is, in conjunction with a Quarterly Rate Adjustment Mechanism (QRAM) rate change. Depending on the timing of the Board's Final 2010 Rate Order, the Company would propose to implement final 2010 rates into billing in conjunction with either the April 1, 2010 or the July 1, 2010 QRAM rate change.

Witnesses: J. Collier
A. Kacicnik

Revenue Adjustment Rider (Rider E)
Should the final 2010 rates be implemented on April 1, 2010, then Rider E will capture the difference in revenue between interim and final rates for the period between January 1, 2010 and April 1, 2010. Similarly, Rider E will capture the difference in revenue between January 1, 2010 and July 1, 2010, should the final 2010 rates be implemented on July 1, 2010.

The Rider E derivation / mechanism would be applied in the same way if final 2010 rates were implemented in between QRAM rate changes such as May 1, 2010. However, as stated above, a rate change implementation outside of the QRAM is not desirable from customer communication and billing perspectives.

Further, the Company would propose to clear Rider E on a one month prospective basis (i.e., over the month of April 2010 for April 1, 2010 implementation or over the month of July for July 1, 2010 implementation).

2010 Rate Impacts and Schedules
Note that there would be no change to the rate impacts or rate schedules presented in the Company's evidence as both represent annualized impacts. Rider E will capture the difference in revenue between interim and final rates for the period between January 1, 2010 and the final 2010 rates implementation date.

Witnesses: J. Collier
A. Kacicnik

SCHOOL ENERGY COALITION INTERROGATORY #2

INTERROGATORY

[Ex. B/1/1, p. 3] Please advise the approvals, if any, the Applicant is seeking in this proceeding with respect to return on equity. If any approvals are being sought, or any indications from the Board of the appropriateness of any future action or position, please advise what evidence the Applicant will be filing with respect to its 2010 cost of capital or any component thereof.

RESPONSE

The Company recently responded to a letter sent to the Board by counsel for the Industrial Gas Users Association in connection with this matter. EGD's response letter is attached for reference, at Exhibit I, Tab 4, Schedule 10. At this time, the matter is still pending comment from the Board. The letter, found at Exhibit I, Tab 4, Schedule 10, sets out EGD's position regarding consideration of return on equity (specifically, for the purposes of earnings sharing calculations) in this proceeding.

Witnesses: J. Denomy
M. Lister

SCHOOL ENERGY COALITION INTERROGATORY #3

INTERROGATORY

[Ex. B/2/1/A, p. 1] Please provide the source of the 7.31% cost of long term debt in the calculation. If it is from a previous proceeding, please provide the calculation and a reference to the Board's decision approving it. If it is not from a previous proceeding, please provide the calculation together with supporting evidence.

RESPONSE

The 7.31% cost of long term debt is the 2007 Board Approved rate contained within the 2007 Test Year proceeding, EB-2006-0034 Phase I, Decision and Final Rate Order, Appendix A, Schedule 4. A schedule in support of the rate, which was not part of the Rate Order, is attached.

Witnesses: K. Culbert
T. Ladanyi

CALCULATION OF COST RATES
FOR CAPITAL STRUCTURE COMPONENTS
BOARD APPROVED 2007 TEST YEAR

Line No.		Col. 1 Average of Monthly Averages	Col. 2	Col. 3 Carrying Cost
		($Millions)		($Millions)
	Long and Medium-Term Debt			
1.	Debt Summary	2,250.0		164.4
2.	Unamortized Finance Costs	(15.6)		-
3.	(Profit)/Loss on Redemption	-		-
4.		2,234.4		164.4
5.	Calculated Cost Rate		7.31%	
	Short-Term Debt			
6.	Calculated Cost Rate		4.12%	
	Preference Shares			
7.	Preference Share Summary	100.0		5.0
8.	Unamortized Finance Costs	(0.1)		-
9.	(Profit)/Loss on Redemption	-		-
10.		99.9		5.0
11.	Calculated Cost Rate		5.00%	
	Common Equity			
12.	Cost Rate		8.39%	

Witnesses: K. Culbert
T. Ladanyi

SCHOOL ENERGY COALITION INTERROGATORY #4

INTERROGATORY

[Ex. B/2/1/A. p. 2] Please provide a continuity chart, broken down by asset class, for all of the assets included in rate base in this Y-Factor calculation, showing for each class the gross assets added in each year, depreciation taken and retirements, and closing assets, as well as the annual rate base calculation.

RESPONSE

The following page contains gross plant and accumulated depreciation continuity charts for the power generation projects.

Witnesses: K. Culbert
T. Ladanyi

Witnesses: K. Culbert
T. Ladanyi

POWER GENERATION GROSS PLANT
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES

Line No.		Col. 1 Opening Balance Jan.2008	Col. 2 2008 Additions	Col. 3 Closing Balance Dec.2008	Col. 4 2008 Average of Monthly Averages	Col. 5 2009 Additions	Col. 6 Closing Balance Dec.2009	Col. 7 2009 Average of Monthly Averages	Col. 8 2010 Additions	Col. 9 Closing Balance Dec.2010	Col. 10 2010 Average of Monthly Averages
		($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)
1.	Land rights (471)	-	7,359.9	7,359.9	306.7	-	7,359.9	7,359.9	-	7,359.9	7,359.9
2.	Mains (475)	-	14,965.6	14,965.6	7,499.8	6,586.1	21,551.7	16,886.5	475.0	22,026.7	22,006.9
3.	Measuring and regulating equip. (477)	-	488.3	488.3	466.1	-	488.3	488.3	-	488.3	488.3
4.	Total	-	22,813.8	22,813.8	8,272.6	6,586.1	29,399.9	24,734.7	475.0	29,874.9	29,855.1

POWER GENERATION CONTINUITY OF ACCUMULATED DEPRECIATION
YEAR END BALANCES AND AVERAGE OF MONTHLY AVERAGES

		Opening Balance Jan.2008	2008 Depreciation	Closing Balance Dec.2008	2008 Average of Monthly Averages	2009 Depreciation	Closing Balance Dec.2009	2009 Average of Monthly Averages	2010 Depreciation	Closing Balance Dec.2010	2010 Average of Monthly Averages
		($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)
5.	Land rights (471)	-	-	-	-	(368.4)	(368.4)	(184.2)	(368.4)	(736.8)	(552.6)
6.	Mains (475)	-	(265.3)	(265.3)	(87.4)	(640.8)	(906.1)	(561.9)	(849.2)	(1,755.3)	(1,330.0)
7.	Measuring and regulating equip. (477)	-	(23.1)	(23.1)	(10.6)	(25.2)	(48.3)	(35.7)	(25.2)	(73.5)	(60.9)
8.	Total	-	(288.4)	(288.4)	(98.0)	(1,034.4)	(1,322.8)	(781.8)	(1,242.8)	(2,565.6)	(1,943.5)
9.	Rate Base - PP&E value (row 4. + 8.)				8,174.60			23,952.90			27,911.60

SCHOOL ENERGY COALITION INTERROGATORY #5

INTERROGATORY

[Ex. B/4/5] Please explain the large amount of unbilled revenue in Class 6 relative to its total revenue and relative to other classes.

RESPONSE

Within the Revenue Cap per Customer Incentive Regulation Model, consistent with the approach used to design rates in a cost of service environment, the Company uses the assignment of revenue requirement (Exhibit B, Tab 4, Schedule 10, pp.1-9) as a guide to establish proposed rates. The assignment of revenue requirement for 2010 to Rate 6 equals $852.24 million as shown at Exhibit B, Tab 4, Schedule 10, page 1, Column 3, Item 4. The proposed revenue for Rate 6 equals $852.35 million as shown at Exhibit B, Tab 4, Schedule 5, page 1, Column 4, Item 2. Rate 6 has a revenue to cost ratio of 1.0 and therefore only recovers the allocated revenue requirement through the proposed billed and unbilled revenues. This can be seen at Exhibit B, Tab 4, Schedule 10, page 1, Column 3.

The amount of unbilled revenue is determined by measuring the change in unbilled revenue generated from rates applied to the December 2009 unbilled forecast of volumes and number of customers relative to revenue generated from the rates applied to the December 2010 unbilled forecast of volumes and number of customers. Factors impacting the level of unbilled revenue between December 2009 and December 2010 can include change in usage per customer, customer migration between sales and T-service, and contract rate classes.

The factor leading to the level of Rate 6 unbilled revenue reflects a change from T-service to Sales service from December 2009 to December 2010 (i.e., proportionally more customers are forecast to be on sales service). As sales service revenues include commodity costs, a higher level of unbilled revenue is produced for Rate 6. In total the sum of the billed and unbilled revenue for Rate 6 recovers its allocated revenue requirement for 2010.

Witnesses: J. Collier
A. Kacicnik
I. Chan

SCHOOL ENERGY COALITION INTERROGATORY #6

INTERROGATORY

[Ex. B/7/1, p. 2] Please provide a table showing, for each rate class, the total amounts of refunds to, or recoveries from, that rate class related to deferral and variance accounts, on a monthly basis commencing April 2010 and continuing for twelve months, and assuming that the Applicant's proposals for clearance of accounts, in this and all other current and planned proceedings, are accepted by this Board.

RESPONSE

The table below shows the total rate class allocation of the 2008 Deferral and Variance account balances to be cleared as two equal installments in April and May 2010 as directed and approved by the Board in the 2008 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review, EB-2009-0055. These amounts combine the principal and interest amounts shown in Columns 1 and 2, respectively, of the referenced exhibit above (Exhibit B, Tab 7, Schedule 1, p. 1).

ALLOCATION OF 2008 DEFERRAL & VARIANCE
ACCOUNT BALANCES BY RATE CLASS, EB-2009-0055

		($000's)
1.1	RATE 1	15,848.7
1.2	RATE 6	1,214.0
1.3	RATE 9	(4.9)
1.4	RATE 100	6,195.3
1.5	RATE 110	3,151.0
1.6	RATE 115	135.9
1.7	RATE 125	(13.2)
1.8	RATE 135	62.2
1.9	RATE 145	(5.3)
1.10	RATE 170	(2,462.6)
1.11	RATE 200	259.7
1.12	RATE 300	(2.0)
1.		24,379.0

At this time, the Company does not have a proposal for clearance of the 2009 accounts as information required is incomplete. The principal and interest amounts shown in Columns 3 and 4 for deferral and variance accounts to be cleared commencing July 1, 2010 are current estimates at a point in time. Estimates for some accounts are not available at this time.

An application to clear the 2009 account balances July 1, 2010 as agreed to in the EB-2007-0615 Settlement Agreement is planned for submission in March 2010.

Witnesses: K. Culbert
A. Kacicnik
D. Small

SCHOOL ENERGY COALITION INTERROGATORY #7

INTERROGATORY

[Ex. C/1/1, p. 4] Please advise what approvals, if any, are being sought in this proceeding with respect to the clearance of the accounts listed in para. 5 on this page.

RESPONSE

Exhibit C, Tab 1, Schedule 1 along with Exhibit B, Tab 7, Schedule 1, are filed in order to provide information and the status of three distinct groupings of accounts;

a) deferral and variance accounts and amounts which have already undergone a review or agreement and have received Board approval for future clearance,
b) deferral and variance accounts which have received Board approval to be established for the recording of amounts but have yet to undergo a review of amounts requested for clearance and receive Board approval for future clearance and,
c) deferral and variance accounts to be established relative to the EB-2007-0615 Board Approved settlement agreement for the 2010 fiscal year

With respect to the accounts listed within paragraph 5, no additional approvals are being sought within this proceeding but rather will be requested within a future deferral and variance account application for review and clearance approval.

As indicated within Exhibit C, Tab 1, Schedule 1, page 4, paragraph 5, the accounts listed within the paragraph were all approved to be established in prior proceedings. Amounts in each of the 2009 CASDA, 2009 OBSDA & OBAVA, and the 2008 DSMVA, LRAM and SSMVA have already been reviewed or agreed to and approved by the Board for future clearance.

For the remaining accounts in paragraph 5, EGD provided the list of accounts for reference purposes only and as indicated, is not seeking approval to clear them within the 2010 application but rather will seek a review and approval of amounts for future clearance in a 2009 Deferral and Variance Accounts for review application which is anticipated to be filed in March 2010.

Witnesses: K. Culbert
A. Kacicnik
D. Small

SCHOOL ENERGY COALITION INTERROGATORY #8

INTERROGATORY

[Ex. C/1/1, p. 4] Please advise which of the listed accounts in para. 5, if any, have a zero balance as of December 31, 2009. If any of those accounts is proposed to be continued for 2010, please provide the reasons why the account remains necessary.

RESPONSE

EGD provided an update to Exhibit B, Tab 7, Schedule 1 reporting December 31, 2009 balances on January 22, 2010. Each of the referenced deferral and variance accounts is required for use in 2010 dependent on events and amounts which may occur relative to the approved description of the account. Each of the referenced accounts was initially established in previous Board Approved Settlements or Decisions (EB-2009-0043, EB-2008-0408, and EB-2008-0106).

Witnesses: K. Culbert
A. Kacicnik
D. Small

SCHOOL ENERGY COALITION INTERROGATORY #9

INTERROGATORY

[Ex. C/1/4, p. 5] Please advise the total amount of PST paid by the Applicant in each of 2008 and 2009, and disaggregate those totals into amounts charged to operating costs, and amounts charged to capital. Please provide any forecasts in the Applicant's possession dealing with PST, HST, and/or HST input tax credits for 2010, and the rationale and supporting analysis behind those forecasts.

RESPONSE

As indicated in response to Board Staff Interrogatory #14 at Exhibit I, Tab 1, Schedule 14, EGD does not currently record sales tax separately within its actual or budgeted financials. EGD is in the process of analyzing, where possible, the impacts of HST to the Company from a cost and potential earnings impact and does not currently possess any forecasts of such impacts.

Please see the response to BOMA Interrogatory #10 at Exhibit I, Tab 3, Schedule 10, for further discussion of the potential impact of the proposed PST / HST change.

Witness: K. Culbert

VECC INTERROGATORY #1

INTERROGATORY

Is EGDI planning to file an application (similar to EB-2008-0055) regarding Earnings Sharing for 2009? Provide details.

RESPONSE

Yes. EGD, annually within the term of the approved Incentive Regulation methodology, will file an Earnings Sharing Calculation, and Deferral and Variance account review application as soon as reasonably possible after the public release of year end financial results.

This is in compliance with the description of Issue 11.1 in the EB-2007-0615 Board Approved Settlement Agreement, Exhibit N1, Tab 1, Schedule 1, pages 28 & 29 (filed for reference in this proceeding at Exhibit E3, Tab 1, Schedule 1).

Witness: K. Culbert

VECC INTERROGATORY #2

INTERROGATORY

Exhibit B Tab 1 Schedule 3 Page 1 Table 1

a) Provide the 2009 Q3 and 2009 Q4 Indices and Annualized Inflation Growth Rates.
b) Compare these to the values in Table 1.
c) Discuss how timing of the IRM adjustment can/should affect the estimate of the Inflation factor.

RESPONSE

a) Table 1 from Exhibit B, Tab 1, Schedule 3, page 1 has been updated for 2009 Q3 data only as 2009 Q4 data is not available yet.

Table 1 - Inflation Factor
Calculation of Inflation Factor with 2009 Q3 Result

Col. 1	*Col. 2*	*Col. 3*
Quarter	Index Value	Annualized Growth Rate
2006 Q4	108.50	
2007 Q1	109.80	
2007 Q2	110.60	
2007 Q3	110.20	
2007 Q4	110.60	
2008 Q1	111.30	
2008 Q2	112.40	
2008 Q3	113.60	
2008 Q4	114.20	3.25%
2009 Q1	114.40	2.79%
2009 Q2	114.40	1.78%
2009 Q3	114.30	0.62%
Average (Rounded to 2 decimal places)		2.11%

Witness: J. Denomy

b) Once the 2009 Q3 annualized growth rate is considered in the inflation factor formula, thus removing the 2008 Q3 annualized growth rate, the 2010 estimated inflation factor has decreased to 2.11% from 2.73%.

c) If the timing of the IRM adjustment takes place during a period of relatively low inflation, as measured by the Canadian GDP IPI FDD, a relatively low estimate will prevail. Conversely, if the timing of the IRM adjustment takes place during a period of relatively high inflation, a relatively high estimate will prevail.

However, the establishment of the GDP IPI FDD (including the timing of the data to be used) is stipulated in paragraph 2.1.1 of the IR Settlement Agreement which is filed in this proceeding at Exhibit E, Tab 1, Schedule 1.

Witness: J. Denomy

VECC INTERROGATORY #3

INTERROGATORY

Customer Additions and Volume Forecast

Exhibit B Tab 1 Schedule 4 Page 1; Exhibit B Tab 1 Schedule 5 Appendix B

a) Does EGD have an econometric model to forecast residential customer additions?

b) If so
    i. Provide details of the inputs, dependent and independent variables coefficients etc.
    ii. Show how the model was used to forecast the 2010 additions.

c) If not provide a schedule that lists the sources of all significant inputs used by EGD to prepare the forecast, including employment, housing starts etc.

d) How does EGD use the data for example use a median value of forecasts.

e) Provide an update/comparison of 2009 actual data in column 7 of Table 1.

f) Provide the latest 2010 forecast data from EGDs sources and provide a comparison the Data in Table 1, Column 8.

g) Explain why forecast housing starts are so significantly reduced in 2010 given the continued expansion of the GTA. In particular address why new construction is severely affected (31,739 - 22,616). Include in the explanation both positive factors such as the availability of low cost financing for builders and new homeowners as cited in paragraph 5 as well as negative factors.

h) Does EGD agree that higher customer additions than forecast would boost net income and earnings in 2010? Please comment.

Witnesses: I. Chan
J. Denomy
S. Murray
T. Ladanyi

RESPONSE

a) The Company does not use an econometric model to forecast residential customer additions. The customer additions forecasting process is a bottom up forecast meaning that the forecast is developed by the sales team using inputs from builders, economic information/trends, professional judgment and informed opinion. Please refer to Exhibit B, Tab 1, Schedule 4, paragraph 2 for an explanation of the Company's customer additions forecasting process.

b) i) Please see the Company's response to question a).

ii) Please see the Company's response to question a).

c) Please see below the economic data and the source of each data series which is considered during the Company's residential customer additions forecasting process.

Witnesses: I. Chan
J. Denomy
S. Murray
T. Ladanyi

Residential Customer Additions Variable Input Schedule

Col. 1 Variable:	*Col. 2* Source:
Regional Housing Starts	Canadian Mortgage and Housing Corporation: Housing Starts, Completions and Under Construction Activity Ledgers
Regional Unemployment Rate	Statistics Canada - CANSIM II Database
Regional Employment Growth	Statistics Canada - CANSIM II Database
Regional Consumer Prices	Statistics Canada - CANSIM II Database
Ontario Real GDP	Ontario Ministry of Finance - Quarterly Ontario Economic Accounts
Ontario Real Manufacturing Output	Statistics Canada - CANSIM II Database
Ontario Wage Rate	Statistics Canada - CANSIM II Database
Ontario Retail Sales	Statistics Canada - CANSIM II Database
Ontario Housing Starts	Statistics Canada - CANSIM II Database
Ontario Consumer Prices	Statistics Canada - CANSIM II Database
Ontario Unemployment Rate	Statistics Canada - CANSIM II Database
Ontario Employment Growth	Statistics Canada - CANSIM II Database
1 Year Mortgage Rate	Statistics Canada - CANSIM II Database
3 Year Mortgage Rate	Statistics Canada - CANSIM II Database
5 Year Mortgage Rate	Statistics Canada - CANSIM II Database
Real Residential Natural Gas Price	Enbridge Gas Distribution Rate Handbook

d) Each of the Regional-specific variables is forecast using the Company's internal grassroots forecasting approach.

Each of the Ontario-specific variables is forecast using an average of the outlook's from Canadian banking and financial institutions.

Witnesses: I. Chan
J. Denomy
S. Murray
T. Ladanyi

Each of the mortgage rate variables is forecast using the Company's internal grassroots forecasting approach.

The assumptions used to generate the residential natural gas price forecast can be found in Exhibit B, Tab 1, Schedule 7, page18, paragraph 15.

e)

Table 1
Economic Outlook Summary - 2009 Comparison

Col. 1	*Col. 2*	*Col. 3*
Variable	2009 Forecast	2009 Actual
ONTARIO REAL GDP (% CHANGE)	-1.8	NA
MORTGAGE RATE 5 YEAR TERM (%)	5.23	5.63
ONTARIO HOUSING STARTS (000's)	55.1	50.4
CENTRAL REGION HOUSING STARTS (000's)	31.2	25.8
EASTERN REGION HOUSING STARTS (000's)	5.3	6.0
NIAGARA REGION HOUSING STARTS (000's)	0.9	1.0
FRANCHISE AREA HOUSING STARTS (000's)	37.5	32.7

Witnesses: I. Chan
J. Denomy
S. Murray
T. Ladanyi

f)

Table 1
Economic Outlook Summary - 2010 Update

Col. 1	*Col. 2*	*Col. 3*
Variable	Former 2010 Forecast	Updated 2010 Forecast
ONTARIO REAL GDP (% CHANGE)	2.1	2.7
MORTGAGE RATE 5 YEAR TERM (%)	5.37	5.60
ONTARIO HOUSING STARTS (000's)	56.8	59.1
CENTRAL REGION HOUSING STARTS (000's)	30.3	30.3
EASTERN REGION HOUSING STARTS (000's)	5.3	5.3
NIAGARA REGION HOUSING STARTS (000's)	1.0	1.0
FRANCHISE AREA HOUSING STARTS (000's)	36.6	36.6

g) At the time when the 2009 Board Approved Budget of residential new construction customer additions was decided upon, the depth of 2009 recession had yet to be realized. At that time, the Company expected customer additions to materialize in line with its recent past. However, the 2010 forecast of residential new construction customer additions was generated with a more complete set of information. As a result, the 2010 customer additions forecast was determined under the belief that the Ontario economy would likely be restructuring in 2010.

In terms of positive trends which can support residential new construction customer additions in 2010, the Company identified historically low lending rates. The Company maintains that lower lending rates may act as a boon to construction growth and lower rates may also act as a mitigating factor to further declines in the construction market.

Negative trends, which the Company acknowledged when crafting its 2010 residential new construction customer additions estimates, were a restructuring economy and the threat of competition from resale properties on housing starts. Following what was an active 2009 in the resale market, given exceptionally low mortgage financing rates, newly designed fiscal programs and more competitive

Witnesses: I. Chan
J. Denomy
S. Murray
T. Ladanyi

prices, the Company expects housing demand to continue to see competition from existing properties in 2010, but to a lesser degree than in 2009.

Overall, with resale properties competing with new homes to satisfy housing demand, accompanied by a positive but restrained economic expansion, 2010 customer additions, particularly residential new construction, will face challenges in 2010. However, accounting for sustained low lending rates and the continuation of government-sponsored programs, the Company feels residential new construction customer additions of 22,616 remains a reasonable estimate for 2010. As well, the Company also maintains that total 2010 customer additions forecast is consistent with the above positive and negative factors.

h) Higher customer additions than forecast could marginally increase net income in 2010 provided the incremental cost to attach such customers does not exceed the associated revenue.

Witnesses: I. Chan
J. Denomy
S. Murray
T. Ladanyi

VECC INTERROGATORY #4

INTERROGATORY

Exhibit B Tab 1Schedule 5 Page 12 Paras 23-25

a) Provide more details of the estimate of 6.5% savings from new construction basement insulation.

b) Show how this translates to the 1.8 10^6 m^3 in Table 2.

c) Does EGD have data on sales of mid- efficiency furnaces in 2009 (since the notice of Regulation was issued).

d) Explain why an assumption of all new and replacement furnaces meeting 90% efficiency cannot be used.

RESPONSE

(a) As previously explained in EB-2008-0219, Exhibit I, Tab 7, Schedule 6, part g and paragraph 23 of Exhibit B, Tab 1, Schedule 5, page 12, 6.5% is calculated by applying the Government of Ontario's estimated savings of 6.5% (=28%-21.5%) which is the difference between the new building code effective December 31, 2008 (28%) and the old building code effective December 31, 2006 (21.5%).

(b) As stated in paragraph 23 of Exhibit B, Tab 1, Schedule 5, page 12, 1.8 $10^6 m^3$ is calculated by multiplying the 6.5% mentioned above to the 2009 residential new construction customer estimate volumes that have space heating furnaces. As most of the new customers will not move to their new houses and start consuming gas effective January 1 2009, the currently reported 1.8 $10^6 m^3$ impact reflects the first year's partially effective impact. Beyond 2009, the fully effective impact of this new building code will be much larger than this first year's impact, all else being equal.

(c) No.

(d) In contrast to the changes to Building Code in respect of which the Government of Ontario provided estimated energy savings to the public, Natural Resources Canada did not provide corresponding numbers for the amended Regulations that

Witnesses: I. Chan
T. Ladanyi

are effective December 31, 2009 and require that the minimum performance level, Annual Fuel Utilization Efficiency ("AFUE"), for residential gas-fired furnaces will be 90% (high-efficiency) instead of the previous 78% (medium-efficiency). As mentioned in paragraph 25 of Exhibit B, Tab 1, Schedule 5, due to lack of public data availability the corresponding further reduction in average use has not been incorporated into the current volumetric forecast, however, the non-weather impact in average use would be subject to the true-up mechanism (AUTUVA).

VECC INTERROGATORY #5

INTERROGATORY

Exhibit B Tab 1Schedule 5 Page 32 Para 51

a) Update the 2009 total volumes to reflect actual.

b) Discuss the main variances and implications for the 2010 forecast.

RESPONSE

(a) Consistent with previous filings, 2009 actual volumes will be filed as part of 2009 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review. This is in accordance with the EB-2007-0615 Settlement Agreement which provides that the Company will submit the 2009 actual results following the completion of Company's audited year end results approved for public release.

(b) Same as above.

Witnesses: I. Chan
T. Ladanyi

VECC INTERROGATORY #6

INTERROGATORY

Exhibit E, Tab 1, Schedule 1- Settlement Agreement

a) Provide the 2009 Average Use True Up Calculation in accordance with the EB-2007-0615 Settlement Agreement Paragraph 4.1 and the methodology regarding "Average Use True-Up Variance Account" or "AUTUVA").

b) Discuss whether (given the timing) this adjustment should be included in the 2010 DRR calculation or retained in the AUTUVA for disposition in spring 2010.

RESPONSE

a) As indicated in the response to SEC Interrogatory #7 at Exhibit I, Tab 6, Schedule 7, EGD will be seeking a review and requesting approval of the 2009 AUTUVA balance within its application for a review of a 2009 Earnings Sharing Mechanism calculation, scheduled to be filed in March 2010. As a result, the Company will provide responses to account detail requests within that proceeding.

b) The impact of changing average use information and its impact on volume forecasts is determined in accordance with the established methodologies and procedures previously approved by the Board. The determination of the amount in the AUTUVA has been calculated in the manner prescribed and approved by the Board within the EB-2007-0615 Settlement Agreement.

   In accordance with the Settlement Agreement, the amount in the 2009 AUTUVA is specific to variances which have occurred in the 2009 Fiscal Year relative to average use assumptions which underpinned Rate 1 and Rate 6 volumes in setting 2009 rates. Consistent with previous filings, the 2009 AUTUVA would be disposed as part of the 2009 Earnings Sharing Mechanism mentioned above. Consequently, this 2009 adjustment should not be included in the 2010 DRR calculation.

Witnesses: I. Chan
K. Culbert

VECC INTERROGATORY #7

INTERROGATORY

Exhibit B-2- 2, Updated 2010-01-22. Table 2

a) Provide details of the current 2010 low income program initiatives and Budgets including a breakdown between the Social Housing and owner occupied housing sectors.

b) Detail what steps EGD will take if the Government provides direction on low income DSM during the rate year. Include the constraints on increasing the Low Income program budget and ramping up the delivery of the programs.

c) Is EGD spending money on program development for the Multi-residential (non social housing) sector? If so provide details f the budgets initiatives and timing.

d) What is the upset $ limit on the use of the DSMVA for Low income spending relative to the $1,666,980 base budget?

e) What are the constraints on the use of DSMVA to enhance the LI programs (e.g. TRC)?

RESPONSE

Enbridge's 2010 DSM Plan for the low income sector was filed in EB-2009-0154, Phase II. With the exception of the low income solar thermal water heater proposal, this Plan was approved as filed in the Board's Decision and Order, dated December 14, 2009.

The evidence filed in this proceeding to support the amount of the DSM Y-Factor has been updated to reflect removal of $1.4 million for the solar thermal water heater proposal but otherwise no changes are being proposed to the low-income DSM program. Please refer to Exhibit B, Tab 2, Schedule 2, page 4, updated 2010-01-22.

a) Please refer to EB-2009-0154, Phase II, Exhibit D, Tab 2, Schedule 1, pages 1 to 4, filed 2009-10-15, for program details and budgets. The Enbridge low income programs are not delineated by housing sector.

Witnesses: A. Mandyam
P. Squires

b) Please refer to Enbridge's response to VECC Interrogatory #1, part (d), filed at EB-2009-0154, Phase II, Exhibit 1, Tab 8, Schedule 1.

c) There are no program development costs specific to the multi-residential non-social housing sector.

d) In a letter dated September 28, 2009, the Board directed Enbridge and Union Gas to "file 2010 DSM [low income] plans based on the existing DSM framework." Under this framework, established in the EB-2006-0021 Generic DSM Proceeding, recovery of program expenditures via the DSMVA of up to 15% of the approved budget is not program specific and accessible only when the overall DSM portfolio TRC target is achieved.

e) As described in part (d) above, the parameters of the DSMVA are not program specific. The Board-approved rule for accessing the DSMVA is that "the utility may recover the amounts in the DSMVA from ratepayers provided it has reached 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." (EB-2006-0021 Decision with Reasons, p. 13).

Witnesses: A. Mandyam
P. Squires

VECC INTERROGATORY #8

INTERROGATORY

Exhibit B Tab2 Schedule 1:

a) Provide the total cost of each of the York Region and Greenfield South projects;

b) Provide a summary of the EBO 188 Feasibility analysis for each project including NPV of costs and revenues and PI.

c) Provide the in-service date) on the status of the York Regional Energy Centre project.

d) Please provide an update (in-service date etc) on the status of the Greenfield Pipeline.

e) Why should the Greenfield project be included in 2010 unless there is a firm contractual commitment?

f) Please advise whether the Board has granted Leave to Construct for either or both of the York Region and Greenfield projects.

RESPONSE

a) As indicated in Ex. B, T2, S1, page 2, the total project cost for the York Energy Centre Pipeline Project is estimated to be $39.1 million, details of the costs are outlined in EB-2009-0187 Leave to Construct application at Exhibit C, Tab 2, Schedule 1.

   The total project cost for the Greenfield South Pipeline Project is forecast to be $2.04 million as indicated in Ex. B, T2, S1, page 2. Contractual commitment for the Greenfield South project is outstanding, therefore no leave to construct application has been filed to date.

b) A summary of the feasibility analysis for the York Energy Centre Pipeline Project was filed in the EB-2009-0187 Leave to Construct application at Exhibit E, Tab 1, Schedule 2.

   For the Greenfield South Pipeline Project, refer to a) above.

Witnesses: K. Culbert
T. Ladanyi

c) The in-service date of the York Energy Centre Pipeline Project is April 15, 2011.

d) The in-service date for the Greenfield South Pipeline Project is forecast to be in 2011, pending contractual commitment to proceed with the project.

e) The Greenfield South Pipeline Project is forecast to begin in 2010 with an in-service date within 2011. It is not included within the power generation revenue requirement determination for 2010.

f) The York Energy Centre Pipeline Project Leave to Construct application, EB-2009-0187, was filed with the Board on September 3, 2009. Board decision is pending.

   A Leave to Construct application has not been filed with the Board for the Greenfield South Pipeline Project.

Witnesses: K. Culbert
T. Ladanyi

VECC INTERROGATORY #9

INTERROGATORY

Exhibit B Tab 3 Schedule 1Page 4Para 11 and 14

a) Provide a summary of the December 2009 Pension Valuation.

b) Compare this to the Mercer estimates at Para 14.

c) Confirm whether or not the valuation has been filed with the FCSAO.

d) Discuss the implications of the valuation for the Proposed Z Factor.

e) Explain why EGD has not updated its Z factor request of $18.9 million in the updated Exhibit B Tab 1 Schedule 2 at line 25?

f) Provide a 2010Revenue requirement calculation schedule for pension funding to reflect the updated December valuation.

g) Confirm the Impact on the updated DRR of $1 ,003.26 million at line 28 of B-1-2 page 1.

h) Why should not the proposed pension cost variance account(Para. 29) use the December 2009 estimate as the “fulcrum” rather the $18.9 million 2008 estimate?

RESPONSE

a) The valuation at December 2009 will become available in April 2010.

b) This comparison can be done only after the valuation as at December 31, 2009 becomes available.

c) The valuation is not currently available, thus has not been filed.

d) The implications for the proposed Z-factor will be known after the valuation becomes available in April 2010.

Witnesses: J. Haberbusch
N. Kishinchandani

e) The Z factor request has not been updated on account of non-availability of updated information.

f) The December 2009 valuation is not currently available, thus this calculation cannot be completed.

g) The impact can be provided only after the valuation as at December 2009 becomes available.

h) Only a formal year-end valuation can form basis of determination of contributions. Interim estimates provide guidance, but do not qualify to form the basis of determination of such contributions. The Company acknowledges that the performance of financial markets in 2009 will likely result in the final contribution requirement being in the lower end of the contribution range of $3.0 million and $18.9 million noted in the evidence, however a final determination can only be made once the valuation report at December 31, 2009 becomes available.

Witnesses: J. Haberbusch
N. Kishinchandani

VECC INTERROGATORY #10

INTERROGATORY

Exhibit B Tab 3 Schedule 2, Page 4 Para's 11 and 12

a) Provide the history of cross bore incidents and remediation costs since 2005.

b) Explain why the problem was not part of the 2007 base capital and operating budgets leading into the IRM plan.

c) Justify/qualify in more detail than provided at Para 33, the cross bore issue and proposed 2010 Z factor and DRR of $3.64 million based on each of the Board's Z factor criteria.

d) Provide a multi-year plan for Cross Bore work.

e) Provide a Schedule that sets out the historic and projected cost by major capital and O&M cost category and the DRR corresponding to the multi-year plan.

RESPONSE

a) Enbridge began to collect crossbore information in 2007.

Year	# Cross bores discovered
2007	3
2008	7
2009	4
2010	1

The most recent cross bore was found on February 3, 2010 in Niagara-on-the-Lake. A NPS 2 PE gas main was found that had penetrated a NPS 6 sewer lateral. The cross bore was discovered during the process of obtaining sewer locates by Enbridge's private service provider prior to the installation of a new gas service. This is an example of the success of Enbridge's current construction procedures that were implemented to eliminate the creation of new cross bores.

The approximate cost for remediation is $5000 per occurrence.

Witnesses: C. Clark
L. Lawler

b) Costs related to crossbores were not part of the 2007 base costs or rates leading into the IRM plan because the issues and associated costs were not well enough known at that time. In 2007, Enbridge was working to determine the scope of the crossbore problem. The Company did not have enough history, knowledge or cost information to include program costs in the 2007 base capital and operating budgets leading into the IR plan period.

c) The Company has filed detailed information underlying the principal elements of its forecast of capital and operating budgets related to its sewer lateral initiative for the 2010 Test Year at Exhibit B, Tab 3, Schedule 2 in Attachment B.

This information provides a detailed program breakdown for the following:

i) $1.5 million - New construction and excavation techniques;
ii) $1.0 million - Investigation and identification of potential crossbore locations;
iii) $2.7 million - Public information communication campaign and follow up;
iv) $0.3 million - IT upgrades and tracking methodology; and
v) $0.3 million - Research and development program.

The revenue requirement for the Company's forecast of operating and capital expenditure costs in the 2010 Test Year has been filed as Appendix B to Exhibit B, Tab 3, Schedule 2.

At paragraph 33 of Exhibit B, Tab 3, Schedule 2, and throughout that Schedule, Enbridge set out the reasons why the sewer lateral initiative qualifies for Z-factor treatment. The evidence makes clear that neither the urgency, nor the cost/scope of the sewer lateral initiative were fully known at the time that the IR settlement was reached, and that the Company now needs to undertake these activities to address emerging safety concerns.

d) The Company is unable to provide a multi year plan or forecast of activity for crossbore work at this point. Awareness of the issue and the related response to customer inquiry, as well as the programs cost will be driven by the 'uptake' of the program.

Similar to "Call Before You Dig" program, the units of response required will tend to increase over time as public awareness increases. At this early stage of the sewer lateral initiative, attempting to forecast customer response to the communication activity would be very difficult.

Witnesses: C. Clark
L. Lawler

It is precisely for this reason that the Company has proposed a variance account in order to track differences between the actual costs and the forecast of costs that the Company is proposing to recover through the Z-factor. This proposed cost recovery mechanism will ensure that it is only the incremental costs actually incurred that are ultimately recovered from ratepayers.

e) Please refer to the response provided in point “d” above.

Witnesses: C. Clark
L. Lawler

VECC INTERROGATORY #11

INTERROGATORY

Exhibit E Tab 1, Schedule 1 Page 55- Settlement Agreement

a) Provide a schedule that compares the 2010 allocation to Rate Classes to that shown at page 55 of the EB-2007-0615 Settlement Agreement.

b) Comment on the differences for the Rate 1 and Rate 6 classes.

RESPONSE

a) A similar schedule to Exhibit N1, Tab 1, Schedule 1, page 55 of the Settlement Agreement was provided as part of the 2010 Application (EB-2009-0172) at Exhibit B, Tab 4, Schedule 10, page 7. Both exhibits are provided on the next page for ease of comparison.

b) The assignments of DRR before Y and Z factors for 2010 (Table 2, Item 1.0) have remained fairly consistent with the estimates for 2010 from EB-2007-0615 as contained in the Settlement Agreement (Table 1, Item 1.5).

Rate 1 assignment for 2010 is relatively unchanged from the estimate. Rate 6 assignment is higher than the estimate, reflecting customer migration from contract rates to Rate 6. Please note that the Company's IRM Model allows forecasts and allocators to be updated annually. This ensures that the assignment of revenue requirement by rate class and consequently rate impacts, remains responsive to factors such as customer growth, volumetric gains or losses, and customer migration between various rates and service offerings.

The Total DRR for 2010 (Table 2, Item 2.0) is higher than the estimate (Table 1, Item 1.0) mostly due to proposed Z-factors for Pension Funding and Cross bores/Sewer Laterals, raising Total DRR assignments for Rate 1 and Rate 6 accordingly.

Witnesses: A. Kacicnik
M. Suarez

Table 1: Settlement Agreement (page 55)

								2010								
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	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	Total DRR	986.0	659.8	256.9	1.3	27.0	10.9	8.2	6.4	0.7	4.8	5.2	2.3	0.3	0.2	1.6
	Y Factor: Other															
1.1	2010 Gas in Storage & Working Cash Carrying Cost	43.1	20.2	17.4	-	2.3	0.7	0.3	-	-	0.6	1.1	0.5	-	-	
1.2	DSM 2010	24.3	11.9	6.1	-	2.5	0.6	1.1	-	0.1	0.5	1.4	-	-	-	
1.3	CIS/ Customer Care 2010	89.2	82.0	7.1	-	-	-	-	-	-	-	-	0.0	-	-	
	Y Factor: Capital Investment															
1.4	2010 Leave to Construct	3.0	1.4	1.1	0.0	0.1	0.1	0.1	0.2	0.0	-	-	0.0	-	-	
	Total Y-Factor	159.6	115.4	31.8	0.0	5.0	1.3	1.5	0.2	0.1	1.2	2.5	0.6	0.0	0.0	0.0
1.5	Total DRR minus Y-Factor	826.4	544.3	225.1	1.3	22.1	9.6	6.7	6.2	0.6	3.7	2.7	1.7	0.3	0.2	1.6

Table 2: 2010 Evidence (Ex B T4 S10 p7)

2010 Distribution Revenue Requirement with Y- and Z- Factor Detail
December 31, 2010

(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 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	DRR before Y- & Z-Factors	816.7	542.7	242.2	0.6	0.0	8.8	3.5	7.2	0.9	3.4	2.0	2.1	0.4	0.2	2.8
	Y Factor: Other															
1.1	2010 Gas in Storage & Working Cash Carrying Cost	36.7	17.9	16.3	-	-	0.5	0.1	-	-	0.6	0.8	0.5	-	-	
1.2	DSM 2010	26.7	11.6	8.9	-	-	1.6	1.4	-	-	1.5	1.7	-	-	-	
1.3	CIS/ Customer Care 2010	95.7	87.8	7.8	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	Y Factor: Capital Investment															
1.4	2010 Leave to Construct	3.6	1.7	1.5	0.0	-	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	-	
1.5	Total Y-Factor	162.7	119.0	34.5	0.0	0.0	2.1	1.6	0.2	0.0	2.1	2.5	0.5	0.0	0.0	0.0
1.6	DRR with Y-Factors	979.4	661.7	276.8	0.6	0.0	11.0	5.1	7.4	0.9	5.5	4.5	2.6	0.4	0.2	2.8
	Z Factor: Proposed															
1.7	2010 Pension Funding requirement	18.9	12.8	5.4	0.0	0.0	0.2	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	-
1.8	2010 Crossbores/Sewer Laterals Program	3.6	2.5	1.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	-	0.0	0.0	-
1.9	Total Z-Factor (Proposed)	22.5	15.3	6.4	0.0	0.0	0.3	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0
2.0	Total DRR with All Y-& Z-Factors	1,001.9	677.0	283.1	0.6	0.0	11.2	5.2	7.6	0.9	5.6	4.6	2.7	0.4	0.2	2.8

VECC INTERROGATORY #12

INTERROGATORY

Exhibit E Tab 1, Schedule 1 Page 58- Settlement Agreement

a) Provide an update and comparison to the Schedule shown at Page 58, including actual and forecast rate impacts and actual and forecast base DRRs 2008-2012.

b) Provide an update/comparison of Bill impacts2008-2012 in the schedule on Page 59 of the settlement Agreement.

RESPONSE

a) Please see table on page 2.

b) Please see table on page 3.

Witnesses: J. Collier
A. Kacicnik

ESTIMATED 2008-2012 RATE IMPACTS

Rate Class	ADR 2008[1] T-Service Rate Impact Estimate	ADR 2008[1] T-Service Rate Impact Approved[6]	ADR 2009[2] T-Service Rate Impact Estimate	ADR 2009[2] T-Service Rate Impact Approved[7]	ADR 2010[3] T-Service Rate Impact Estimate	ADR 2010[3] T-Service Rate Impact Proposed[8]	ADR 2011[4] T-Service Rate Impact Estimate	ADR 2012[5] T-Service Rate Impact Estimate
1	0.1%	0.3%	2.1%	0.5%	1.6%	1.7%	1.5%	1.7%
6	0.0%	0.1%	1.8%	0.4%	1.3%	1.2%	1.2%	1.4%
9	0.1%	0.1%	0.8%	0.0%	1.1%	1.1%	1.2%	1.6%
100	0.1%	0.1%	1.3%	-0.3%	1.0%	0.9%	0.9%	0.9%
110	0.1%	0.1%	1.1%	-0.3%	1.0%	0.9%	0.9%	0.9%
115	0.1%	0.1%	1.1%	-0.4%	0.8%	0.6%	0.8%	0.8%
135	0.6%	0.6%	0.9%	-0.1%	0.9%	0.8%	0.9%	0.9%
145	0.2%	0.2%	1.0%	0.0%	0.9%	0.9%	0.8%	0.8%
170	0.4%	0.4%	1.0%	-0.4%	0.9%	0.8%	0.9%	0.9%
200	0.4%	0.4%	1.0%	0.0%	0.9%	0.6%	0.8%	1.0%

Rate Class	ADR 2008 Distribution Rate Impact		ADR 2009 Distribution Rate Impact		ADR 2010 Distribution Rate Impact		ADR 2011 Distribution Rate Impact	ADR 2012 Distribution Rate Impact
125	0.0%	0.0%	0.7%	0.1%	0.7%	1.0%	0.7%	0.7%
300	0.1%	0.1%	0.9%	0.1%	0.9%	1.0%	0.9%	0.9%

Notes:
1. - 2008 Distribution Revenue Requirement of $935 M (Estimate), 2008 Distribution Revenue Requirement of $938 M (Approved)
2. - 2009 Distribution Revenue Requirement of $963 M (Estimate), 2009 Distribution Revenue Requirement of $974 M (Approved)
3. - 2010 Distribution Revenue Requirement of $986 M (Estimate), 2010 Distribution Revenue Requirement of $1,003 M (Proposed)
4. - 2011 Distribution Revenue Requirement of $1,006 M
5. - 2012 Distribution Revenue Requirement of $1,029 M
6. - From EB-2007-0615, Exhibit C, Tab 6, Schedule 8
7. - From EB-2008-0219, Exhibit B, Tab 3, Schedule 1, Page 4
8. - From EB-2009-0172, Exhibit B, Tab 4, Schedule 1, Page 3

Typical Customer Estimated T-Service Bill Impacts from 2008 to 2012
As Per Settlement Proposal

	October 1, 2007 T-Service Bill (1) Annual Bill ($)	Estimated 2008 T-Service Bill Annual Bill ($)	Approved 2008 T-Service Bill Annual Bill ($)	Estimated 2008 T-Service Bill Annual $ change	Approved 2008 T-Service Bill Annual $ change	Estimated 2009 T-Service Bill Annual $ change	Approved 2009 T-Service Bill Annual $ change	Estimated 2010 T-Service Bill Annual $ change	Proposed 2010 T-Service Bill Annual $ change
Rate 1									
Rate 1 T-Service Bill Impact	409.37	416.18	416.66	6.81	7.29	8.68	8.07	6.93	12.65
Note: (1) based on annual consumption of 1,955 m3									
Rate 1 T-Service Bill Impact	558.77	559.89	556.36	1.12	(2.41)	11.67	(0.94)	9.32	6.31
Note: (1) based on annual consumption of 3,064 m3									
Rate 1 T-Service Bill Impact	772.67	755.35	756.56	(17.32)	(16.11)	15.75	(13.66)	12.57	(2.64)
Note: (1) based on annual consumption of 4,691 m3									
Rate 6									
Rate 6 T-Service Bill Impact	2,879.90	2,882.78	2,844.04	2.88	(35.86)	51.73	26.51	39.42	45.45
Note: (1) based on annual consumption of 22,606 m3									
Rate 6 T-Service Bill Impact	5,023.61	4,710.21	4,716.59	(313.40)	(307.02)	84.52	(5.71)	64.40	30.32
Note: (1) based on annual consumption of 43,285 m3									
Rate 115									
Rate 115 T-Service Bill Impact	3,356,187.92	3,359,795.82	3,358,151.13	3,607.90	1,963.21	36,957.75	(19,803.81)	25,690.51	23,305.38
Note: (1) based on annual consumption of 69,832,850 m3 at 80% Load Factor									

VECC INTERROGATORY #13

INTERROGATORY

Exhibit B Tab 4 Schedule 1 Page 7 of 8 Plus Appendix

a) Provide the details of the costs underlying new System Gas Administration charges (similar to Appendix A for DPAC, except include derivation of incremental costs).

b) Compare to historic costs.

c) Delineate the change in the allocation of this cost to system gas customers.

d) Provide the 2010 (forecast) of system gas customers in each class compared to 2009 (forecast and Actual).

e) Is the SG admin charge a fixed or variable cost (or both)?

RESPONSE

a) The System Gas Fee was updated for the 2010 rate adjustment application using the incremental costing methodology approved by the Board in the Commodity Pricing, Load Balancing and Cost Allocation Methodologies for Natural Gas Distribution proceeding (EB-2008-0106).

The details of the incremental costs comprising the System Gas Fee are presented in the table below.

	2010 Incremental Costs	
	System Gas	
Gas Acquisition	$	272,822
Contract Management	$	208,155
Nominations	$	141,597
Invoicing & Payment Processing	$	122,349
Demand Forecasting & Supply Planning	$	68,585
Total incremental costs for activities	$	813,508
Fringe benefits for labour component of incremental costs	$	373,500
TOTAL	$	1,187,008

Witnesses: J. Collier
A. Kacicnik
M. Suarez

b) Historic costs were also provided in EB-2008-0106 as part of the interrogatory response to the Gas Marketer Group (Exhibit IR8, IR14, IR18, IR19, Schedule 27, pp. 2 and 3). The response is replicated below.

d) The functions identified as system gas related pertain to the roles and responsibilities which were performed at that time. The grouping of the responsibilities into functions may not be comparable to the 2009 grouping of functions however the overall incremental cost amount is comparable. The breakdown of the existing level of incremental costs for the system gas functions is as follows:

	Incremental Cost Estimate for 2002	
	System Gas	
Gas Acquisition	$	270,460
Risk Management	$	68,800
Contract Management	$	86,818
Nominations	$	33,907
Invoicing & Payment Processing and reporting	$	142,921
Supervision	$	89,537
Billing	$	6,157
Total incremental costs for activities	$	698,600
Fringe benefits for labour component of incremental costs	$	186,212
TOTAL	$	884,812

e) The breakdown of the $1.14M system gas costs by function for 2009 based on the proposed incremental costing approach is as follows:

	Incremental Cost Estimate for 2009	
	System Gas	
Gas Acquisition	$	257,398
Contract Management	$	200,738
Nominations	$	145,641
Invoicing & Payment Processing	$	115,433
Demand Forecasting & Supply Planning	$	64,708
Direct Purchase Billing Adjustments		N/A
Total incremental costs for activities	$	783,918
Fringe benefits for labour component of incremental costs	$	354,252
TOTAL	$	1,138,169

The current System Gas Fee has remained based on $884k (i.e., 2002 level of incremental cost) since 2002. Incremental cost estimates were provided for 2009 as part of the evidence in EB-2008-0106. The Company has updated the level of these incremental costs for the 2010 Rate Adjustment as per the Board's Decision in EB-2008-0106.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

c) As per the Board's Decision in EB-2008-0106, there is no change in the allocation methodology of incremental costs to support System Gas Management to customers, only the level of incremental costs is updated for 2010. The cost is allocated to rate classes on the basis of System Gas Sales (volumetric), thereby resulting in the same unit rate for each rate class (see Exhibit B, Tab 4, Schedule 7, page 1, Line 3.3). The proposed system gas fee equals 0.0224 cents/m^3 for all rate classes. The System Gas Fee is recovered as part of the Gas Supply Charge.

d) The forecast of system gas customers for 2010 and for 2009 is provided below, with references to exhibits filed. As actual average customers for 2009 are unavailable at this time, the 2009 estimate is provided instead.

Please note that incremental system gas costs, or the System Gas Fee, are allocated to rate classes on the basis on system gas sales volumes, not system gas customers.

System Gas Average Customer by Rate Class

	2010 Budget EB-2009-0172 ExB T1 S5 AppA p.1	**2009 Budget** EB-2008-0219 ExB T1 S5 AppA p.1	**2009 Estimate** EB-2009-0172 ExB T1 S5 AppA p.2
Rate 1	1,152,358	1,096,540	1,131,079
Rate 6	108,729	103,202	108,689
Rate 9	24	25	24
Rate 100	-	-	30
Rate 110	36	33	35
Rate 115	1	1	1
Rate 135	4	1	4
Rate 145	12	9	12
Rate 170	6	4	6
Rate 200	1	1	1
Total System Gas	1,261,171	1,199,816	1,239,881

e) As highlighted in response to c) above, the System Gas Fee is a variable charge recovered as part of the Gas Supply Charge to System Gas customers. The same unit rate of 0.0224 cents/m^3 applies to all rate classes.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

VECC INTERROGATORY #14

INTERROGATORY

Exhibit B, Tab 4, Schedule 6 Page 1 Item 1.01 Exhibit B Tab 4 Schedule 9 Page 2

a) Provide details of the agreement in the EB-2007-0615 Settlement Agreement regarding Residential Customer Charges.

b) Provide details of the 2007 (base), 2008 and 2009 residential customer charges.

c) Explain why the Increase in the 2010 Customer charge from $16.00 to $18.00 is appropriate and in line with the Settlement Agreement.

d) For a low volume Residential customer with most consumption in the first rate block provide a schedule that shows the impact on the Distribution portion of the bill and total bill impact of the $2.00 change in customer charge. Compare this to the average DRR change of 1.7% and average total bill impact.

RESPONSE

a) and b) The 2007 Monthly Residential Customer Charge was $11.95. The following table outlines the annual changes to Monthly Residential Customer Charges agreed upon in the Settlement Agreement:

Changes to Monthly Customer Charges ($)	
Year	**Rate 1**
2008	$14.00
2009	$16.00
2010	$18.00
2011	$19.00
2012	$20.00

This information can be found at Exhibit E, Tab 1, Schedule 1, (p. 33 of the Settlement Agreement).

Witnesses: J. Collier
A. Kacicnik

c) The 2010 customer charge increase from $16.00 to $18.00 reflects Section 12.3.1 of the Settlement Agreement, as shown in the Table in response to a) and b). As is agreed upon in this section, the current Board-approved rate design principles have been maintained, and the agreed upon monthly charge increase has been made on a revenue neutral basis within the rate class.

d) A low volume customer consumes approximately 1,081 m^3 per year and generally uses natural gas for water heating and one other life style application such as a natural gas fireplace or natural gas range. This type of customer represents approximately 1% of the residential customers on Enbridge's system. The average residential customer uses natural gas for space and water heating and consumes approximately 2,622m^3 per year. Approximately 90% of Enbridge customers use natural gas for space and water heating.

Impacts for General & Water Heating and Average Customers are shown in the following table.

Residential Customer Type With Annual Consumption	**T-Service % Impact**	**Total % Bill Impact**
General & Water Htg. (1,081m^3)	5.30%	3.10%
Average Customer (2,622m^3)	1.70%	0.70%

Witnesses: J. Collier
A. Kacicnik

VECC INTERROGATORY #15

INTERROGATORY

Exhibit B Tab 7 Schedule 1

a) Provide details of the costs underlying the Manufactured Gas Plant D/A 2009 MGPDA and Balance of $ 206,600 plus interest of $10,500.

b) Confirm that the balance in the 2009 Manufactured Gas Plant DA (“MGPDA”) will be transferred into a 2010 MGPDA.

c) With regard to Open Bill Service D/A 2009 OBSDA $539,400 and. Open Bill Access V/A 2009 OBAVA $476,700 confirm that the EB-2009-0043 Settlement Agreement indicates the balances in the 2008 Open Bill deferral and variance accounts would be transferred to 2009 accounts.

d) Indicate when these balances will be subject to prudence review and disposition.

RESPONSE

a) Please see response to SEC Interrogatory #7 at Exhibit I, Tab 6, Schedule 7 and VECC Interrogatory #6 at Exhibit I, Tab 7, Schedule 6.

b) Confirmed, as indicated in evidence at Exhibit C, Tab 1, Schedule 1, page 5, paragraph 7.

c) Confirmed, as shown in evidence at Updated 2010-01-22, Exhibit B, Tab 7, Schedule 1.

d) Please see response to SEC Interrogatory #7 and VECC Interrogatory #6.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #16

INTERROGATORY

Exhibit B Tab 7 Schedule 1

a) Provide an updated copy of the IFRS Compliance Plan.

b) With regard to the. International Financial Reporting Standards Transition Costs D/A (2009 IFRSTCDA) balance of $2,060,300 provide more details of the Costs incurred relative to the milestones in the plan.

c) Provide a forward projection 20010-2012 of IFRS Compliance costs relative to the Plan.

RESPONSE

EGD is continuing work towards achieving its IFRS project plan which was filed on April 27, 2009 within EB-2008-0219 at Exhibit TCU-2.1.

As indicated in response to SEC Interrogatory #2 at Exhibit I, Tab 6, Schedule 2, EGD is not seeking the review and approval of the 2009 related deferral and variance account balances in this proceeding but rather will be filing an application for the review and approval of these accounts in an application in March 2010.

The 2009 IFRSTCDA and balances will be included in the list of accounts to be reviewed. EGD will respond to all questions relating to the review of the account in that proceeding.

Witnesses: K. Culbert
N. Kishinchandani

VECC INTERROGATORY #17

INTERROGATORY

Exhibit B Tab 7 Schedule 1

a) With regard to 2009Transactional Services D/A (2009 TSDA) and balance ($7,062,100) and 2008Transactional Services D/A (2008 TSDA) ($6,476,000) provide EGDIs plan for prudence review and disposition of these amounts.

RESPONSE

The 2008 Transactional Services Deferral Account (TSDA) balance has already been reviewed in the EB-2009-0055 proceeding and approved by the Board for clearance in April and May of 2010 in its Decision and Order of August 7, 2009 and a supplementary Decision and Order dated January 6, 2010.

Please see responses to SEC Interrogatory #7 at Exhibit I, Tab 6, Schedule 7 and VECC Interrogatory #6 at Exhibit I, Tab 7, Schedule 6, regarding EGD's plan for a future review and approval for disposition of an amount in the 2009 TSDA.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #18

INTERROGATORY

Exhibits B Tab 7 Schedule 1: C Tab 1Schedule 1 Clearance of Accounts

a) Confirm that 2007 Demand Side Management Account 2007 DSMVA ($616,100) plus interest ($127,500) and the 2008 Transactional Services D/A 2008 TSDA (6,476,000) plus interest(101,000) will be cleared in April/May 2010.

b) Provide details of the derivation of the large amount of interest on the 2007 DSMVA.

c) Provide details of the prudence review for the 2008 TSDA Balance.

d) Why cannot the 2008 Demand Side Management Account 2008 DSMVA - - ($73300) ($56,200 interest) and 2009Transactional Services D/A (2009 TSDA) (balance $7,062,100) also not be cleared in April/May?

e) Provide details of the derivation of the large amount of interest on the 2008 DSMVA.

RESPONSE

a) EGD will clear these account balances in April/May 2010 along with all other deferral and variance account balances as ordered for clearance in the EB-2009-0055, January 6, 2010 Decision and Order.

b) & e) The interest calculated for the 2007 and 2008 DSMVA, is determined by applying the Board's quarterly prescribed interest rate for deferral and variance accounts to a DSMVA principal balance. Interest on the 2007 DSMVA accumulated over a period of three years while interest on the 2008 DSMVA accumulated over a period of two years. The balances in each of the accounts, upon which interest was calculated, were in higher credit positions prior to the year end actual and audited results presented to, and approved by, the Board. In addition to the duration and balances upon which interest was calculated, the interest rate in effect for the majority of the time period was significantly higher than the current Board prescribed rate. The interest credit amounts, to the benefit of ratepayers, were derived in consideration of the above factors.

Witnesses: K. Culbert
A. Kacicnik
D. Small

c) As indicated in response to VECC Interrogatory #17 at Exhibit I, Tab 7, Schedule 17, the review of the 2008 TSDA balance occurred in the EB-2009-0055 proceeding. The Board's Decision in that proceeding dated August 7, 2009, approved a principal balance in the amount of $6,476,000 credit for the 2008 TSDA.

d) The 2008 DSMVA balances were agreed to and proposed to the Board by parties in the EB-2009-0341 DSM proceeding, to be cleared July 1, 2010. The Board ultimately approved the clearance of the accounts for July 1, 2010 in its EB-2009-0341 Decision dated January 19, 2010.

   As indicated in the response to VECC Interrogatory #17, EGD will be requesting a review and approval of the clearance of the 2009 TSDA in a future application and cannot clear its balance until approved by the Board.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #19

INTERROGATORY

Exhibits B Tab 7 Schedule 1; C Tab 1Schedule 1

a) Confirm that the. 2010 Pension Funding Cost VA ("PFCVA"), and 2010 Crossbores / Sewer Laterals Bore VA ("SLCBVA") accounts are contingent on the approval of the related Z-factors.

RESPONSE

The request to establish the 2010 PFCVA and 2010 SLCBVA is related to the associated Z-factor requests. It may be, however, that the deferral or variance accounts related to these matters could be created relative to the benchmark minimum Z-factor threshold amount. This would ensure that only the actual cost of the event is recovered so long as it is at or above the threshold and that any cost incurrence below the threshold would not be recoverable.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #20

INTERROGATORY

Exhibit C Tab 1 Schedule 5 Page 1 of 3
Preamble
" The Ontario Energy Board's ("Board") Gas Distribution Access Rule ("GDAR"), Service Quality Requirements Performance and Measurement ("SQR") establishes the standards for Time to Reschedule Missed Appointments (TRMA). Under Section 7.3.4.2 of GDAR the distributor must attempt to contact the customer to reschedule the work within 2 hours of the end of the original appointment time, 100% of the time."

a) Provide a copy of the Company's April 28, 2009 letter to the Board's Chief Regulatory Auditor.

b) Provide the Response.

c) Provide the 2010 plan and costs of compliance.

d) Provide the 2010 target and comment when TRMA performance is expected to be in compliance.

RESPONSE

a) A copy of the Company's April 28, 2009 letter to the Board's Chief Regulatory Auditor is attached.

b) The Company has not received a response to the April 28, 2009 letter.

c) During 2009 the Company significantly improved the performance on this metric compared to the previous years. The preliminary result was 97% and the cost was $420,000. This was achieved through work done by a cross-functional team. Priorities were to utilize process improvements established in previous years, including meeting the initial appointment and thus eliminating the need for rescheduling. It is the Company's plan to keep the team in place in 2010 in order to maintain performance, augmented by use of additional technology to provide greater visibility to appointments in real time. The associated cost will be approximately $620,000.

Witnesses: K. Lakatos-Hayward
B. Visnjevac

d) The Board set the 2010 target for TRMA at 100% in 2007 when the SQR was introduced. Given the 2009 preliminary result of 97%, we anticipate that we will be approaching compliance in 2010. However, as discussed in Exhibit C, Tab 1, Schedule 5, while rescheduling missed appointments is an important part of SQR achievement attainment of a perfect 100% score is virtually impossible. As a result, the Company has recommended that the TRMA target be reviewed and that a target of 90% would be more appropriate.

Witnesses: K. Lakatos-Hayward
B. Visnjevac

ENBRIDGE

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Norm Ryckman
Director, Regulatory Affairs
phone: 416-753-6280
fax: (416) 495-6072
Email: norm.ryckman@enbridge.com

April 28, 2009

VIA COURIER

Mr. Bill Cowan
Chief Regulatory Auditor
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, On M4P 1E4

Dear Mr. Cowan:

Re: 2008 SQR Report

I am pleased to advise that, as required by the Gas Distribution Access Rule, Enbridge Gas Distribution Inc. (EGD) today submitted the above referenced Report via the OEB web portal. Attached to this letter are two documents which are required to be filed in association with the Report per the provisions of Sections 2.1.9.E and 2.1.9.B of the GDAR:

(i) EGD Emergency Response Procedures
(ii) EGD Billing Accuracy Quality Assurance Program

I also wish to comment and provide explanation on two issues with respect to the data in the SQR Filing.

1. The standard for 2.1.9.C.1, is the number of meters not read for 4 consecutive months or more is "shall not exceed 0.5%". The Company's result for 2008 was 0.69%.

The winter of 2007/2008 provided many challenges for reading gas meters. The weather produced record breaking snowfalls which caused meters to be inaccessible, contributing to the majority of EGD's missed reads.

With the agreed upon deferral of Automated Meter Reading in the 2007 rate case, the replacement of obsolete meter reading equipment became a priority. Equipment was ordered late in 2007 and installation completed by March 2008. However, in January and February 2008, EGD experienced higher equipment failures with the old equipment, resulting in lost reads obtained in the field.

EGD has taken on several initiatives in 2008, to improve and to meet the OEB's target for this standard including: i) upgrades to handheld devices and meter reading software in March, and ii) detailed analysis of 4 or more consecutive estimate accounts as well as action plans to obtain meter reads for these accounts. For example, EGD undertook the following:

- Completed 25,148 additional off cycle reads to reduce the number of 4 or more consecutive estimates;
- Conducted a telephone campaign for 4 or more consecutive estimate accounts to advise customers of their read dates in order for them to provide access to meters; and,
- Process improvements to the Consecutive Estimate automated letter program which starts the process much earlier.

Despite these efforts, EGD was not able to recover from the inclement winter weather resulting in the majority of EGD's missed reads for 2008. However, EGD's first quarter results for 2009 currently indicate that the Company is on track to meet the SQR target of 0.5%.

2. The standard for 2.1.9.D2, contacting the customer within 2 hours of a missed appointment, is 100%. The Company's result for 2008 was 62.8% versus the standard of 100%.

From January 2008 through to July 2008, a committee was established to identify system enhancements which were implemented in August 2008. As a result, the percentage of appointments rescheduled on time improved significantly from 65.5% in August to 81.4% in September.

In the fall of 2008, EGD transitioned to a new Distribution Operations contract, whereby the plan to reduce the percentage of rescheduled appointments was temporarily deferred; however, with the successful transition completed, performance improved to 83.1% for December.

EGD is increasing its efforts towards achievement of this metric and we are confident that our results for 2009 will continue to show improvement. Current year-to-date results for the first quarter of 2009 indicate that 14 appointments were not rescheduled on time resulting in performance of 87%. EGD continues to place priority on this standard and we are committed to achievement of the targeted performance level.
All customer SQR targets other than those identified in this letter were met by the Company, including Appointments Met, and hopefully this demonstrates our commitment.

I would be pleased to meet with you at your convenience to discuss any aspects of this SQR Report.

Sincerely,

Norm Ryckman
Director, Regulatory Affairs

Attachments

ENBRIDGE

ENBRIDGE GAS DISTRIBUTION

Operating & Maintenance Manual
January 2009

Users of the Operating & Maintenance Manual

The O&M Manual has been created to ensure that policies and procedures used in activities related to operation and maintenance of gas distribution plant are documented and meet all legislated requirements.

The procedures contained in this document are mandatory. They have been prepared to ensure consistent and proper application of work practices and must only be carried out by trained and qualified workers. Adhering to these procedures will help to ensure that the Company meets all of its due diligence obligations when performing work.

This manual is available in hard copy and can also be found on the Engineering Portal, which is found on the e-Source Web Site under Communities. From time to time, new or revised policies and procedures will be introduced and the manual updated accordingly. Updates to the manual will be communicated in the form of a "Technical Announcement" which will summarize the change and provide the updated policy and/or procedure.

The new Manual is effective **March 1, 2009**.

If you require clarification or have ideas on how to improve our policies or procedures, please contact Engineering Operations.

David Baxter
Manager, Engineering Operations

Lisa Lawler
Chief Engineer

On Cover: Industrial Site. Service Riser Steel Squeeze-Off Tool up to 2 in.

7.0 EMERGENCY PRACTICES

7.1 Policy

Workers must be prepared to handle emergencies associated with the operation of the distribution system. In addition the Company will investigate, and when required, make safe a reported gas leak, fumes call or odour complaint at no charge to the customer.

The procedures in this section provide a guide for workers who are involved in emergencies related to:

- Gas escapes, distribution and customer owned piping
- Fumes or odour complaints
- Fire and/or explosion including those involving toxic chemicals
- Main or service line breaks
- Supervised entry
- Pressure problems
- Spills reporting
- Low or high odourant levels

For Supervisors and Operations Managers these policies and procedures are supplemented by the Regional Emergency Procedures Manual.

Emergency situations must be judged in the light of actual conditions and the experience and training of operating workers.

7.1.1 Media

Media inquiries must be referred to the Regional Manager or their designee. The Regional Manager is the only person in the Region with the authority to communicate to the media.

7.1.2 Confidentiality

Remember you are the official Company representative on site. Conduct yourself in a calm and professional manner. Do not comment or offer opinions to anyone except your supervisor.

8.0 GENERAL SERVICE PROCEDURES

8.1 Policy

The Company provides prompt high quality service with due regard for employee and public safety. Employees must maintain good public relations and corporate image at all times.

Company employees must follow safe operating practices in accordance with applicable company policies and procedures and applicable codes and standards.

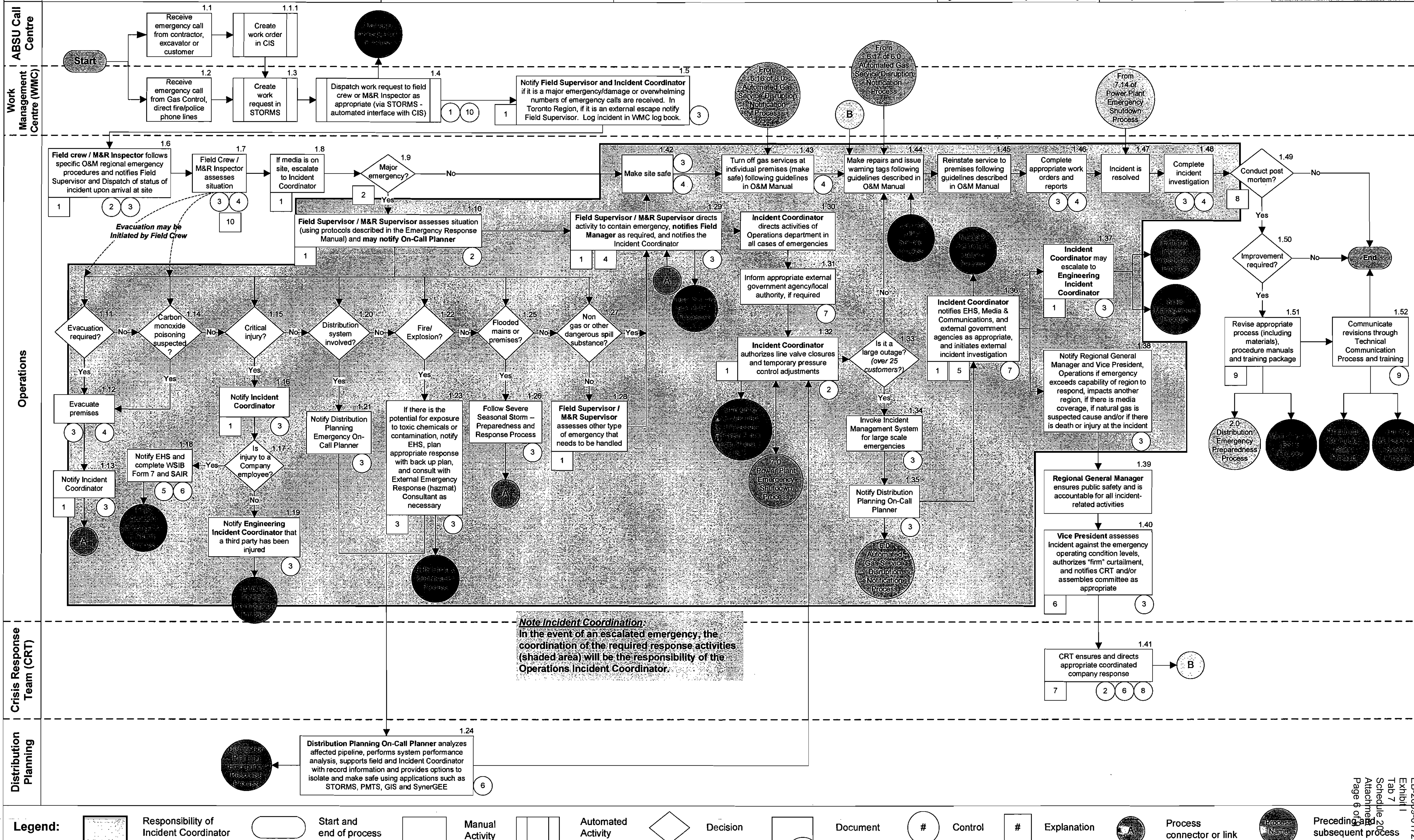
The Company must provide emergency service, government inspections (GI's), appliance inspections, and some minor adjustment service to customer owned equipment at no charge.

Emergency response includes responding immediately to main breaks, gas escapes, fires, fumes, explosions and overpressures.

Customers who call in false alarms or abuse the leak investigation policy must be billed.

ENBRIDGE

Sub Process Title: 1.0 Distribution Emergency Response Process Title: Emergency Management Plan	Start State: An emergency call is received	End State: Revisions are communicated through the Technical Communication Process and training	Project Name: Distribution Management System (DMS) orig. created and revised by: Marlene Wagar	Process Owner's Manager: Doug Lapp Process Owner: Bill Bishop revised by: Marlene Wagar	orig. date: July 2005 rev. date: April 7, 2009 page: 1 of 2



ENBRIDGE

Sub Process Title: 1.0 Distribution Emergency Response **Process Title: Emergency Management Plan**	**Start State** An emergency call is received	**End State** Revisions are communicated through the Technical Communication Process and training	Project Name: Distribution Management System (DMS)	Process Owner's Manager: Doug Lapp	orig. date: July 2005
				Process Owner: Bill Bishop	rev. date: April 7, 2009
			orig. created and revised by: Marlene Wagar	revised by: Marlene Wagar	page: 2 of 2

Explanations

1. The Engineering Incident Coordinator oversees the External Incident Investigation Procedure, consults/advises the Incident Coordinator as necessary and prepares a defense for charges against the Company and its employees.
   The Incident Coordinator or designee is responsible for directing the response and all activities of the field personnel.
   The Field Supervisor is responsible for the direction of field crews and all field personnel on the orders of the Incident Coordinator.
   The Regional Incident Coordinator may request to be notified of all damages.

2. An emergency is considered to be minor if the Field Crew/Inspector is capable of resolving the situation and there is minimal or no impact on the distribution system. An emergency is considered to be major if the Field Crew/Inspector requires additional resources/escalations to contain the emergency and it may or has significantly impacted the distribution system.

3. The External Emergency Response (hazmat) Consultant is consulted for assistance with response plan for fires involving toxic chemicals or contaminated soils.

4. In situations where the source of the suspected leak cannot be readily determined or where other substances are suspected of being the cause of the complaint, EMEC would be called to take samples to identify the source of the odour.
   Where natural gas is suspected but normal procedures have not been adequate to determine the source of the leak, Leak Survey would be contacted to provide assistance.

5. Media Communications is notified if the media is already on site or the incident may generate media enquiry.

6. An "emergency operating condition" is declared if emergency falls within the definition described in the Crisis Response Manual, i.e. insufficient resources available to respond, harm to company, stressed distribution system due to extreme cold weather.

7. The initial response to an emergency situation is handled by the region or business unit affected. If the emergency situation is, or has the potential of escalating beyond a level that can be handled by the region, the corporate group becomes involved, providing assistance or direction as required. During severe emergencies, the response of the Company is directed by the CRT who coordinates the actions of the Company (Crisis Response Manual).

8. A post mortem is conducted to determine if adequate processes and procedures are in place to address an emergency such as flooding, power failure, main break or other unusual occurrences and to mitigate effects of future occurrences. For any incident pertaining to an Operating Policy or where a potential or recurring operating problem is indicated, even though the Regional Incident Coordinator deems the occurrence non-reportable, the Manager, Engineering QA will be informed.

9. May require coordination of efforts, training or instruction to external parties (i.e. MOE, Fire Departments, Hydro, other response groups).

10. Evacuate at 1% LEL in building atmosphere. Call 911 to assist with evacuation of commercial, institution or multi-residential premises.

Controls

(1) Dispatch must respond immediately and have crew on site within one hour. (Operations Scorecard measure and WMC Report)

(2) Training requirements are specified in the Training Management System Process. Incident Coordinators receive incident management training.

(3) Refer to the Emergency Procedures Manual for:
- Escalations and notifications
- Make site safe or isolate hazards
- Responses to fires involving toxic chemicals and back up contingencies
- Incident Management System
- Incident Reporting
- Accident investigation procedure
- Evacuation
- Supervised Entry Procedure
- Severe Seasonal Storm – Preparedness and Response Process and Flood Procedure
- Guidelines for contacting first responders

(4) Refer to the O&M Manual for:
- Make site safe or isolate hazards
- Evacuation
- Supervised Entry Procedure
- Incident reporting
- Accident investigation procedure

(5) The Incident Coordinator immediately notifies MOL, JEHS Committee and the Union if an employee is critically injured and will notify the EHS Manager as soon as is practical. The EHS Manager may make required notifications in consultation with the Incident Coordinator as indicated in the Emergency Procedures Manual.

(6) Documentation:
- WSIB Form 7 and SAIR (Supervisor's Accident Investigation Report)
- Distribution Planning On-Call Planner logs the incident in the Planning logbook
- CRT Committee participation is logged in the CRT logbook
- Accident investigation reports are submitted to Engineering Incident Coordinator

(7) Regulators (TSSA, NEB, MOL) are notified according to the regulator's prescribed protocol as summarized in the Emergency Procedures Manual.

(8) The Chairperson of the CRT shall ensure that the CRT meets yearly to review emergency plans and ensure that the Company's plans are adequate to respond to emergency situations. (Crisis Response Manual)

(9) Revisions are communicated through memos, technical alerts, communiqués, and in-class sessions.

(10) If the emergency is a plant damage, the Damage Prevention Inspector or after hours On-Call is notified.

Legend: Responsibility of Incident Coordinator | Start and end of process | Manual Activity | Automated Activity | Decision | Document | # Control | # Explanation | A Process connector or link | Process Name Preceding and subsequent process

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Customer Care Operations
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anne.creery@enbridge.com

March 30, 2009

File Number:

Ontario Energy Board
2300 Yonge Street
26th Floor
Toronto, ON
M4P 1E4

Dear Board Secretary:

RE: S.7.3.2 of GDAR - Quality Assurance Program

As per the 2008 SQR requirements, we are forwarding to you the processes followed in our current Quality Assurance Program, which are used to validate billing charges when large changes in customer's consumption appear.

Our current processes surrounding the production, review and adjustment (if necessary) of customer bills are as follows:

1. To ensure accuracy, a random set of production bills is manually reviewed every day, based on a predefined set of billing data (ie. accounts on budget billing, accounts on pay as you go, accounts on pre-authorized payment, etc.). The random includes bills for both residential and commercial customers.

2. All bills whose consumption increased by 100% or more during the heating season (and 200% or more during the non heating season) when compared to the previous month are automatically reported each billing day and are reviewed manually for accuracy.

3. All bills whose gas charges are $1,000 or more are automatically reported each billing day and are reviewed manually for accuracy.

4. All bills whose meter readings indicate that there has been no gas consumption for two months (and the meter is still active) are automatically reported each billing day and are reviewed manually for accuracy. The customer is provided with an estimated bill (based on previous history) to avoid a potential large adjustment should the meter be deemed defective following the investigation. The customer is advised on the estimated bill that an investigation is underway.

5. Random audits of billing functions are performed to monitor billing performance.

6. Billing accuracy in also ensured through the rigour and controls in place for changes to our customer information system (eg. rate changes). All customer information system changes are planned, documented, and fully tested before they are promoted to the production version of our customer information system.

Should you have any questions regarding our current processes, please do not hesitate to contact me.

Sincerely,

ACreery

Anne Creery

cc: Chief Regulatory Auditor, Ontario Energy Board

VECC INTERROGATORY #21

INTERROGATORY

Exhibit E Tab 3 Schedule 1 Pages 1 and 2

a) Provide confirmation that EGD is not seeking to reopen the reconsideration of ROE during the IRM plan.

b) Does EGD agree that to do so would constitute an off ramp?

c) With regard to Section 10.1 of the Settlement agreement does EGD agree that this is subject to interpretation and to materiality considerations? Please discuss.

d) Provide full details on the Earnings sharing calculations for 2008 and (unaudited) 2009.

RESPONSE

The Company recently responded to a letter sent to the Board by counsel for the Industrial Gas Users Association in connection with this matter. EGD's response letter is attached for reference, at Exhibit I, Tab 4, Schedule 10. At this time, the matter is still pending comment from the Board.

a) Confirmed.

b) Agreed.

c) With regard to the ROE that is to be used for the determination of Earnings Sharing, EGD does not believe that there is any subjectivity or materiality to consider. The Settlement Agreement clearly indicates that Earnings Sharing will be calculated using the Board's ROE formula, which represents the Board's determination of a fair return, and/or regulatory rules prescribed from time to time. The Board has changed its policy regarding the determination of a fair return standard, per Board file EB-2009-0084.

d) Details on the Earnings Sharing calculation for 2008 can be found under Board file EB-2009-0055. Details on the Earnings Sharing calculation for 2009 will become available in a future proceeding scheduled to be filed in early March, 2010.

Witnesses: J. Denomy
M. Lister