BOARD STAFF INTERROGATORY #1

INTERROGATORY

Account Balances for clearance

Ref: ExA/T2/S1/Appendix A

Please explain why the balances are shown as "Actual at February 28, 2010" when the Settlement Agreement contemplates December 31st year end balances (ref: EB-2007-0615 Settlement Agreement, 12.1.1 (iv) page 31).

RESPONSE

The Company filed February 28, 2010 actual balances for 2009 because they were the current available balances at the time of filing. The February 28, 2010 principal balances are in most cases identical to the December 31, 2009 balances. Exceptions to this occurred within a few accounts where there was a true-up of a year end accrual, and in the 2009 PGVA as a result of the Board approved rider in place through March 31, 2010. While issue 12.1.1 (vii) of the EB-2007-0615 Settlement Agreement contemplates clearance of December 31st balances, actual balances cleared would ultimately be final Board Approved balances. As in past years, final approved balances to be cleared could include: true-ups of year end accruals, true-ups related to other Board decisions (i.e., 2009 PGVA rider), and/or balance adjustments resulting from the Board's decision in the clearance proceeding. Interest balances shown at February 28, 2010, differ from those at December 31, 2009, as a result of carrying balances an additional two months. In accordance with past practice, and Board approvals, interest payable and receivable is calculated until the time of clearance.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Account Balances for clearance

Ref: ExA/T2/S1/Appendix A

Please list the accounts and associated balances that have already undergone a formal Board review process and have obtained Board approval.

RESPONSE

The following is a listing of accounts and principal balances that have already undergone a formal Board review and approval process.

Witness: K. Culbert

Account	Principal Balance ($)		Board Review Proceeding
2008 Demand Side Management V/A	(73,340)		EB-2009-0341
2008 Lost Revenue Adjustment Mechanism	37,291		EB-2009-0341
2008 Shared Savings Mechanism V/A	5,803,222		EB-2009-0341
2009/10 Class Action Suit D/A	23,547,735	[1]	EB-2007-0731
2009/10 Open Bill Service D/A	309,370	[2]	EB-2009-0043
2009/10 Open Bill Access V/A	476,667	[2, 3]	EB-2009-0043

Notes:

1. The EB-2007-0731 Decision approved the clearance of the CASDA balance in equal instalments over a five year period beginning in 2008. The 2008 instalment was cleared in July and August 2008, resulting in the February 2010 balance of $18,838,188.32. The 2009 instalment was approved in EB-2009-0055 and cleared in April and May 2010. The Company is now requesting clearance of the 2010 instalment in this proceeding.

2. In the EB-2009-0043 Decision/Settlement Agreement the Board approved the clearance of the balances in the 2008 Open Bill Service D/A of $309,370 and 2008 Open Bill Access V/A of $476,667. The balances are to be cleared over a three year period, 2010 to 2012, and be shared equally between the Company and ratepayers. The balances in the 2008 accounts were transferred to corresponding 2009 accounts as per the Accounting Order in the same proceeding.

3. There is an additional incremental amount in the 2009 Open Bill Service D/A, to achieve the February 2010 balance of $526,150. The additional amount relates to TMG, OBA stakeholder, and start-up legal charges. The exact magnitude of these amounts was not known during the EB-2009-0043 proceeding, but they were contemplated and agreed to be shared equally between the Company and ratepayers once known. The Company is requesting clearance of the 2010 ratepayer share of these accounts in this proceeding.

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Earnings Sharing Amount

Ref: ExB/T1/S1/page 1

Please provide the calculation details underpinning the ROE established for 2009 for which the earnings sharing formula applies. Please provide the reference to the proceeding in which the Board approved this particular ROE for use in 2009 earnings sharing.

RESPONSE

In the EB-2007-0615 Revised Settlement Agreement (dated February 4, 2008 and approved by the Board on February 11, 2008), at issue 10.1(i), it was established that, the ROE calculated annually by the application of the Board's ROE Formula in any year of the IR Plan, plus 100 basis points, would be the benchmark to which EGD's actual weather normalized ROE would be compared for the purposes of calculating earnings sharing in each year of the IR plan. The calculation details underpinning the 2009 ROE of 8.31%, established using the Board's ROE formula as it existed on the date of calculation were filed in EB-2008-0219 (EGD's 2009 rate proceeding) at Exhibit E, Tab 4, Schedule 1, Appendix A, and is reproduced below.

Table A1
Determination of ROE for 2009

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 6*	*Col. 7*	*Col. 8*
Yield on 10s 3 Months Out[a]	Yield 10s 12 Months Out[a]	Average 10s Yield	Average Spread (30s-10s)[b]	Long Bond Forecast	Difference in Long Bond Forecast	0.75xDifference (Rounded to 2 Decimal Places)	ROE (%)
		(Col. 1+Col. 2)/2		Col. 3+Col. 4	Col. 5-4.61	0.75xCol. 6	8.66+Col. 7
3.50	3.80	3.65	0.49	4.14	-0.47	-0.35	8.31

Notes:
2008 ROE: 8.66
2008 Long Canada Forecast: 4.61
[a] From Consensus Forecasts October 13, 2008
[b] From Financial Post

Witness: K. Culbert

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Earnings Sharing Reference Materials

Ref: ExB/T1/S1/page 1
Ref: ExD/T1/S1/page 1

Please provide the financial statements of each of the corporate entities that were consolidated into the Enbridge Gas Distribution Inc. December 31, 2009 Consolidated Financial Statements as shown at Exhibit D/1/1. Please provide the 2009 unconsolidated financial statements, either audited or unaudited, of the company that owns the distribution business that underpins the Ontario regulated utility disclosures for which the earnings sharing calculation applies.

RESPONSE

The corporate entities consolidated into the EGD Inc. consolidated financial statements (as shown in Exhibit D/T1/S1) include St. Lawrence Gas Inc. and EGD Inc., which owns the distribution business. The financial effects of St. Lawrence Gas Inc. are eliminated in regulatory filings since they do not relate to the business of the Ontario regulated utility. The unaudited non-consolidated financial statements of EGD Inc. are provided in Appendix A to this response.

ENBRIDGE GAS DISTRIBUTION INC.
NON-CONSOLIDATED STATEMENTS OF EARNINGS
(Unaudited)

(millions of Canadian dollars) Year ended December 31,	**2009**
Gas Commodity and Distribution Revenue	**2,302**
Transportation of Gas for Customers	**443**
	2,745
Gas Commodity and Distribution Costs excluding amortization	**(1,735)**
Gas Distribution Margin	**1,010**
Intercompany Dividend Income	**1**
Other Revenue	**108**
	1,119
Expenses	
Operating and administrative	**376**
Depreciation and amortization	**253**
Municipal and other taxes	**47**
Earnings sharing	**19**
	695
	424
Affiliate Financing Income	**63**
Interest Expense	**(188)**
	299
Income Taxes	
Current	**(51)**
Future	**(27)**
Income Taxes	**(78)**
Earnings	**221**
Preferred Share Dividends	**(3)**
Earnings Applicable to the Common Shareholder	**218**

ENBRIDGE GAS DISTRIBUTION INC.
NON-CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

(millions of Canadian dollars) Year ended December 31,	**2009**
Earnings	**221**
Other Comprehensive Income	
Change in unrealized gains on cash flow hedges, net of tax	**1**
Reclassification to earnings of realized cash flow hedges, net of tax	**1**
Other Comprehensive Income	**2**
Comprehensive Income	**224**

ENBRIDGE GAS DISTRIBUTION INC.
NON-CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Unaudited)

(millions of Canadian dollars) Year ended December 31,	**2009**
Preferred Shares	**100**
Common Shares	**1,071**
Contributed Surplus	**215**
Retained Earnings	
Balance at beginning of year	**538**
Earnings applicable to the common shareholder	**218**
Common share dividends	**(188)**
Balance at End of Year	**568**
Accumulated Other Comprehensive Loss	
Balance at beginning of year	**-**
Other comprehensive income	**2**
Balance at End of Year	**2**
Total Shareholders' Equity	**1,956**

ENBRIDGE GAS DISTRIBUTION INC.
NON-CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(millions of Canadian dollars)	
Year ended December 31,	**2009**
Operating Activities	
Earnings	**221**
Depreciation and amortization	**253**
Future income taxes	**27**
Other	**4**
Changes in operating assets and liabilities	**464**
Settlement recoverable *(Note 4)*	-
	969
Investing Activities	
Additions to property, plant and equipment	**(311)**
Additions to intangible assets	**(61)**
Change in construction payable	**(11)**
Other	**(2)**
	(385)
Financing Activities	
Net change in short-term borrowings	**(367)**
Debenture and term note issues	-
Debenture and term note repayments	**(100)**
Preferred share dividends	**(4)**
Common share dividends	**(181)**
Other	-
	(652)
Increase/(Decrease) in Cash and Cash Equivalents	**(68)**
Cash and Cash Equivalents at Beginning of Year	**55**
Cash and Cash Equivalents at End of Year	**(13)**

Cash and Cash Equivalents[1]	**0**
Bank Overdraft	**(13)**
	(13)

ENBRIDGE GAS DISTRIBUTION INC.
NON-CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
(Unaudited)

(millions of Canadian dollars) December 31,	**2009**
Assets	
Current Assets	
Cash and cash equivalents	**-**
Accounts receivable	**751**
Receivable from affiliate companies	**12**
Gas inventories	**392**
Other current assets	**30**
Future income taxes	**-**
	1,185
Property, Plant and Equipment, net	**4,261**
Intangible Assets	**178**
Investment in Affiliate Company	**825**
Interest in Subsidiary Company	**5**
Deferred Amounts and Other Assets	**476**
	6,930
Liabilities and Shareholders' Equity	
Current Liabilities	
Bank overdraft	**13**
Short-term borrowings	**505**
Accounts payable	**715**
Payable to affiliate companies	**4**
Income and other taxes payable	**9**
Dividends payable	**47**
Current maturities of long-term debt	**150**
Future income taxes	**5**
	1,448
Long-Term Debt	**2,011**
Other Long-Term Liabilities	**959**
Future Income Taxes	**181**
Loans from Affiliate Company	**375**
	4,974
Shareholders' Equity	
Share capital	
Preferred shares	**100**
Common shares	**1,071**
Contributed surplus	**215**
Retained earnings	**568**
Accumulated other comprehensive loss	**2**
	1,956
Commitments and Contingencies *(Notes 8 and 9)*	
	6,930

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Transactional Services

Ref: ExB/T3/S1/ page 3 and 4

Please explain the composition of the TS and TSDA amounts and the basis for the adjustment to utility revenue.

RESPONSE

The table below provides a breakdown of the Transactional Services Revenue for 2009 and also provides the calculation underpinning the amount in the 2009 TSDA.

	Storage Optimization	Transportation Optimization	Total Revenue
	$(000's)	$(000's)	$(000's)
Net Revenue	9,850.1	8,262.7	18,112.8
Rate Payer Share - %	90%	75%	
Rate Payer Share	8,865.1	6,197.0	15,062.1
Amount Included in Rates			(8,000.0)
Amount Transferred to TSDA			7,062.1
Utility Revenue (EB-2010-0042 Exhibit B, Tab 3, Schedule 1, page 3 of 4, Line11)			11,050.7
Transactional Services Elimination - EGD Incentive (EB-2010-0042 Exhibit B, Tab 3, Schedule 1, page 4 of 4)			3,050.7

Witnesses: K. Culbert
N. Kishinchandani

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Weather Normalization

Ref: ExB / T4 / S1 / page 2

Please provide a description of the methodology underpinning the weather normalization calculation. Please provide a schedule that shows the elements and the build-up of the $76 million weather normalization adjustment.

RESPONSE

Included below is a brief description of the Company's approved weather normalization methodology. A more extensive description was provided in evidence at Exhibit B, Tab 1, Schedule 5, on pages 33-36 in EB-2008-0219 and is attached to this response for reference.

The weather normalization methodology used by the Company has been approved by the Board and utilized for more than ten years. General Service normalization is conducted on customers at a group level, with customers grouped together into homogenous classes of gas usage within the six regions of the Company's franchise area. Only the heat sensitive portion of consumption is normalized for heat sensitive or balance point meter reading degree days.

Firstly, the total load per customer of a customer group is calculated by dividing the group's consumption by the total customers within this group. Then, baseload per customer is calculated by taking an average of the two non-weather sensitive summer months' total load. Baseload represents non-weather sensitive load, such as, water heating, other non-heating uses. Thereafter, heatload per customer is calculated by subtracting the baseload per customer from the total load per customer. This heatload represents the heat sensitive portion of consumption.

By dividing the heatload per customer by Actual Heating Degree Days, an Actual Use per Degree Day is generated. The Actual Use per Degree Day is then adjusted to reflect normal weather by multiplying the Budget Heating Degree Days. Consequently, total normalized average use per customer is defined as an aggregate sum of baseload use per customer and normalized heatload per customer.

Witness: I. Chan

For contract market customers, a similar process is followed to determine the actual baseload for each contract. Actual heating load is obtained by removing the baseload and the process load from the total consumption, which is then adjusted to reflect normal weather. The actual volumes are also adjusted, where necessary, to the budgeted level of curtailment.

For example, a large volume customer with interruptible contract may be required to reduce or to completely eliminate or curtail the use of gas to balance the Company's gas supply and demand requirements under extreme or peak weathers. Therefore, the actual volumes used by customers would have been lower than budgeted and must be increased to the normal level assumed in the budget.

Table 1 on the next page provides a schedule that shows the elements and the build-up of the $76 million weather normalization adjustment related to gas costs on a calendar month basis as reported at Exhibit B, Tab 4, Schedule 1, page 2.

TABLE 1
2009 WEATHER NORMALIZATION ADJUSTMENT
GAS COST CALCULATION

			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
Item.			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1.1		Normalization Adjustment Sales (10^6m^3)	(167.3)	(7.2)	(3.0)	6.1	0.3	(0.1)	0.0	0.0	0.0	(57.1)	57.4	(36.3)	(207.3)
1.2*		PGVA ($/$10^3m^3$)	351.977	351.977	351.977	279.235	279.235	279.235	242.832	242.832	242.832	236.950	236.950	236.950	
1.3	1.3 = 1.1*1.2	Sales Gas Cost ($Millions)	(58.9)	(2.5)	(1.1)	1.7	0.1	(0.0)	0.0	0.0	0.0	(13.5)	13.6	(8.6)	(69.3)
2.1		Normalization Adjustment Western Transportation Service (10^6m^3)	(117.0)	(5.3)	(3.3)	4.5	0.0	0.0	0.0	0.0	0.0	(17.3)	21.6	(8.7)	(125.5)
2.2*		Transportation cost ($/$10^3m^3$)	48.701	48.701	48.701	42.552	42.552	42.552	41.406	41.406	41.406	40.236	40.236	40.236	
2.3	2.3 = 2.1*2.2	Western Transportation Service Gas Cost ($Millions)	(5.7)	(0.3)	(0.2)	0.2	0.0 ***	0.0 ***	0.0	0.0	0.0	(0.7)	0.9	(0.3)	(6.1)
2.4		Normalization Adjustment Ontario Transportation Service (10^6m^3)	(13.9)	0.8	(0.7)	0.3	0.0	(0.0)	0.0	0.0	0.0	17.7	(14.6)	(13.9)	(24.1)
2.5		Transportation cost ($/$10^3m^3$)**	48.701	48.701	48.701	42.552	42.552	42.552	41.406	41.406	0.000	0.000	0.000	0.000	
2.6	2.6 = 2.4*2.5	Ontario Transportation Service Gas Cost ($Millions)	(0.7)	0.0	(0.0)	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	0.0	(0.7)
3.1	3.1 = 1.3+2.3+2.6	Total Gas Cost ($Millions)	(65.3)	(2.8)	(1.3)	1.9	0.1	(0.0)	0.0	0.0	0.0	(14.2)	14.5	(9.0)	(76.0)

Note
* Both PGVA and Transportation Cost prices are based upon the Board Approved Quarterly Rate Adjustment Mechanism (QRAM) prices.

**Due to the implementation of the Company's new CIS system of eliminating Ontario T-service credits effective September 1, 2009, there is no gas cost dollar associated with Ontario T-service volumes. Please refer to EB-2009-0309, Exhibit Q4-2, Tab 4, Schedule 1, Pages 4-5 for detailed discussion on this elimination.

*** Less than $50,000.

BOARD STAFF INTERROGATORY #7

INTERROGATORY

GDAR Deferral Account

Ref: ExC/T1/S2/

Please list the activities which make up GDAR Compliance costs and give rise to the costs that are being considered for clearance.

RESPONSE

The description of activities which constitute or make up the costs relating to GDAR compliance, the exact wording of which has been included within and approved in EGD's past Board Approved Rate Orders, is as follows.

> The purpose of the 2009 GDARCDA is to record all incremental unbudgeted capital and operating costs associated with the development, implementation, and operation of the Gas Distribution Access Rule. Such costs would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

The $2.8 million requested for clearance in this proceeding is the 2010 revenue requirement associated with the cumulative costs incurred and captured in the 2007, 2008, and 2009 GDARCDA accounts. This treatment is consistent with the Board approved clearance of the 2007 and 2008 GDARCDA accounts through revenue requirement calculations.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #8

INTERROGATORY

GDAR Deferral Account

Ref: ExC/T1/S2/

Please provide GDAR deferral account amounts approved for clearance for 2007 and 2008. What has GDAR compliance actually cost the utility in 2007, 2008 and 2009?

RESPONSE

The actual incremental costs to the Company in 2007, 2008, and 2009 were the costs captured in the 2007, 2008, and 2009 GDARCDA accounts in the amounts of $6,982.6 thousand, $788.9 thousand, and $188.7 thousand, plus accrued interest. These cumulative actual amounts were used to calculate the corresponding revenue requirements approved and/or requested for clearance.

The revenue requirement amounts approved for clearance in relation to the 2007 and 2008 GDARCDA accounts were $859.3 thousand and $825.6 thousand.

Witness: K. Culbert

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Purchased Gas Variance Account

Ref: ExC/T2/S2/page 2

This schedule shows the seven (7) elements that constitute the 2009 PGVA principle for clearance of $(41.7674) million. Please provide a written explanation with supporting back-up, including working papers and schedules where appropriate, to provide additional detail as to the build-up of the elements which make up the amount proposed for clearance.

RESPONSE

It may assist the response to begin by reiterating two items – 1) the $(41.7674) million quoted above includes interest on a projected principle balance of $(39.270) million and 2) as noted at the bottom of ExC/Ts/S2/page2 “Total PGVA” is a projected final balance for the 2009 PGVA. The actual balance proposed for clearance will be determined, and updated, once the impact of the 2009 Rider C, which was in place until March 31, 2010, is determined. That updated information can be seen in the table below

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma
D. Small

	Col. 1	Col. 2	Col. 3
	PRINCIPLE For CLEARING	INTEREST	TOTAL For CLEARING
	($000)	($000)	($000)
PGVA - COMMODITY COMPONENT			
COMMODITY	(642,635.1)	(40,868.8)	(683,503.9)
RIDERC 2009	470,470.7	30,282.9	500,753.6
INVENTORY ADJUSTMENT	116,444.8	7,405.4	123,850.2
Subtotal PGVA Commodity	(55,719.6)	(3,180.5)	(58,900.1)
PGVA - LOAD BALANCING COMPONENT			
SEASONAL PEAKING	(3,914.2)	(248.9)	(4,163.1)
SEASONAL DISCRETIONARY	2,022.9	128.6	2,151.5
Subtotal PGVA Load Balancing	(1,891.3)	(120.3)	(2,011.6)
PGVA - TRANSPORTATION COMPONENT	12,731.4	809.7	13,541.1
PGVA CURTAILMENT PENALYTY COMPONENT	(395.7)	(25.2)	(420.9)
TOTAL PGVA	(45,275.2)	(2,516.3)	(47,791.5)

It may be appropriate to provide some background information regarding the PGVA and how dollar amounts are booked to the account.

Prior to the implantation of the current QRAM methodology that became effective January 1, 2010 EGD would provide a schedule setting out a forecast of the projected year-end PGVA balance as a part of its QRAM application. This projected balance includes actual purchase costs to date and a forecast of purchase costs for the remainder of the year versus the applicable Reference Price, the impact of the Reference Price change on the System Supply inventory volume, as well as, a forecast of any Rider C collections/refunds.

For the purposes of the QRAM applications the variances associated with EGD's purchase costs are deemed to be all commodity related. The projected year-end PGVA schedule provided as part of the QRAM application does not contemplate or include items such as the impact of TCPL toll changes on the delivery of Direct Purchase

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma
D. Small

volumes, the impact of such toll changes on inventory relating to BGA balances, LBA Charges, Curtailment Non-Compliance Penalties, and Supply UOG penalties. These elements are typically cleared to system and direct purchase customers through the year end clearing of the PGVA administered as one time adjustment on customers' bills.

At year-end once the final audited balance is known, a detailed analysis of all the Underlying components of the PGVA is conducted. The year end balance includes the elements listed above, which are not included in the QRAM forecasts of PGVA balance, and the final balances for the elements which were included, but at a forecasted level in the QRAMs. The underlining principle is that any variances between actual and forecasted acquisition costs are captured in the PGVA and are then collected/refunded to customers.
.
Throughout the year the actual purchase costs are referenced against the PGVA price thereby creating the dollar value to be booked to the PGVA. Under the current methodology for PGVA disposition, the Company disaggregates its PGVA entries by major type of purchase i.e., Empress Supplies, Nova Supplies, Alliance Supplies, Chicago Supplies, Ontario Discretionary Supplies, and Peaking Supplies only at year end to determine the dollars associated with the commodity, transportation, and load balancing elements. The purpose of this disaggregation is so that dollars within the PGVA can be allocated to the various rate classes based on the Board approved methodology including average demand and load balancing needs.

In order to determine this breakdown it is necessary to break the purchases down by quarter and then compare those costs versus the costs that were assumed for that same quarter in the applicable QRAM. For example, January to March actual purchase costs are compared with the January to March costs underpinning the January QRAM, April to June purchase costs with the April to June costs underpinning the April QRAM.

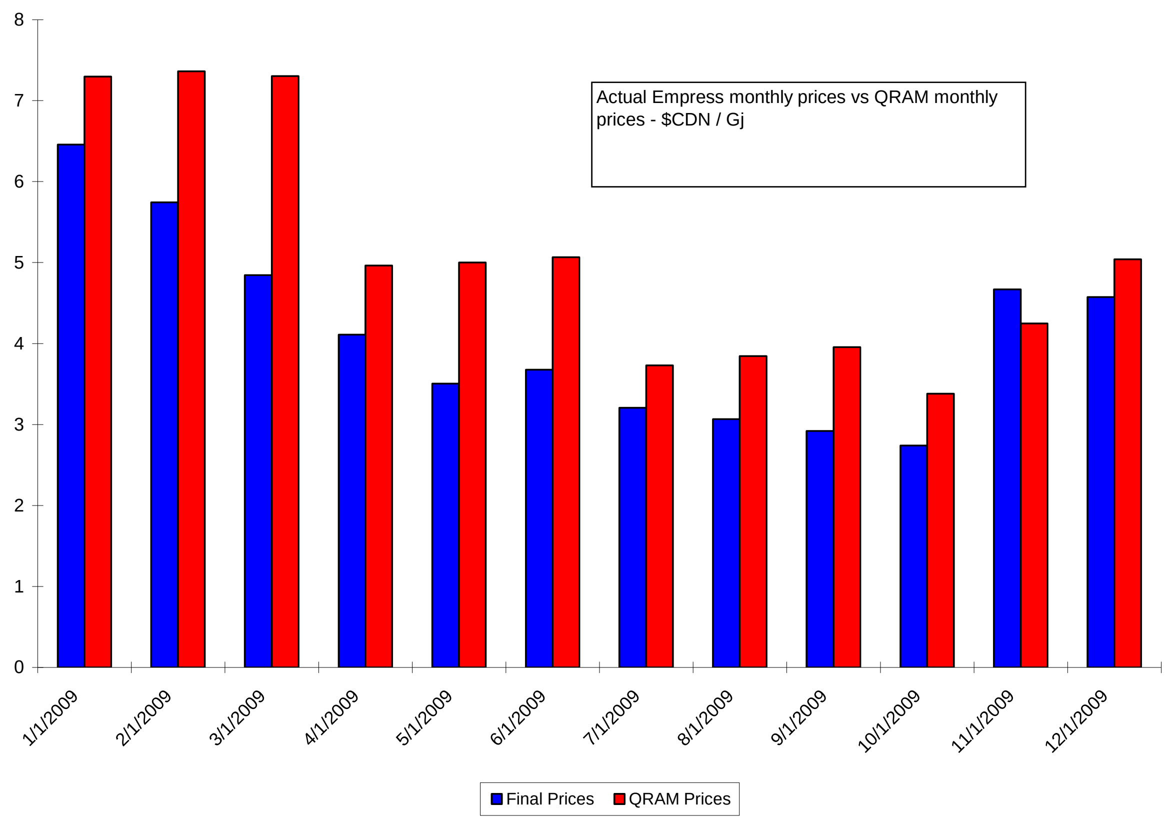
The next step is then to break the variance(s) down between volume variance(s) and price variance(s). The price variances are then broken down between Commodity and, if necessary, Load Balancing.

A similar analysis is required of the balance that is transferred from the previous years PGVA account.

Hopefully, it is self-evident that the amount of backup information for this level of calculations is extensive and would not lend itself to a concise interrogatory response.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma
D. Small

What EGD can readily provide is a comparison of actual and forecasted monthly Empress prices throughout 2009 which will help to illustrate the magnitude of the dollar impact changing prices had on the 2009 PGVA.



Also for informational purposes please refer to EGD's October 2009 QRAM (EB-2009-0309) where at Exhibit Q4-3, Tab 1, Schedule 2, page 2 EGD was forecasting a 2009 year-end PGVA balance of $253.1 million to be refunded to customers. That projection was based upon a forecast of gas supply purchases and acquisition costs for the period July 2009 – December 2009 using a 21 day forecast of monthly prices determined over the period July 17, 2009 – August 14, 2009. Actual monthly prices for the September 2009 to December 2009 period declined over that period which can also be seen from the graph above.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma
D. Small

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 2

a) Please confirm that the escalation factor approved in EB-2008-0219 for 2009 was 0.85% based on a GDP IPI FDD of 1.54% and an inflation coefficient of 55%.

b) What level would the escalation factor have had to been in 2009 to reduce the normalized return on equity from 11.20% to the benchmark ROE of 8.31%?

RESPONSE

a) The Company confirms that the escalation factor approved in EB-2008-0219 for 2009 was 0.85% based on a GDP IPI FDD of 1.54% and an inflation coefficient of 55%.

b) Prior to providing a response, the Company will state its concern that the calculation is misleading and irrelevant. However, the stark, mathematical response would be an escalation factor of 93.44% (100% minus 6.56%).

   That is, the Distribution Revenue per Customer 2009 (Beginning) would have to decline using a factor of 93.44% in order to reduce the Company's 2009 revenue to the point where the normalized return would equal 8.31% holding all other 2009 elements constant.

Witness: K. Culbert

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 1, page 8 & Exhibit B, Tab 4, Schedule 1, page 8 of EB-2009-0055

Please reconcile the UCC Carry Forward balances at the end of 2008 in Exhibit B, Tab 4, Schedule 1, page 8 of EB-2009-0055 with the UCC at Beginning of Year for 2009 shown in Exhibit B, Tab 4, Schedule 1, page 8 of the current application.

RESPONSE

The ending utility UCC balances shown in Exhibit B, Tab 4, Schedule 1, page 8 of the EB-2009-0055 proceeding were obtained from the 2008 year end CCA and tax provisions included in the financial results. The CCA provision and resultant UCC balances were derived by adding estimated 2008 net additions to actual final utility UCC balances from the Company's 2007 tax return, and then applying the appropriate CCA rates. The same process is required when calculating the year end tax provision and financial results in any given year. Therefore, the opening utility UCC balances for 2009, shown at Exhibit B, Tab 4, Schedule 1, page 8, of this proceeding, are the actual final ending 2008 utility UCC balances from the 2008 tax return.

Witness: K. Culbert

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 1

Please update the schedule to reflect the actual final 2009 PGVA balance noted in footnote 7.

RESPONSE

The referenced schedule has been updated to include the final 2009 PGVA balance and corresponding interest forecast.

Witnesses: K. Culbert
D. Small

ENBRIDGE GAS DISTRIBUTION INC.
DEFERRAL & VARIANCE ACCOUNT
ACTUAL & FORECAST BALANCES

Line No.	Account Description	Account Acronym	Col. 1 Actual at February 28, 2010 Principal ($000's)	Col. 2 Actual at February 28, 2010 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2010 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2010 Interest ($000's)
	Non Commodity Related Accounts					
1.	Demand Side Management V/A	2008 DSMVA	(73.3)	(56.1)	(73.3)	(56.3)
2.	Lost Revenue Adjustment Mechanism	2008 LRAM	37.3	0.1	37.3	0.2
3.	Shared Savings Mechanism V/A	2008 SSMVA	5,803.2	5.3	5,803.2	24.2
4.	Class Action Suit D/A	2009/10 CASDA	18,838.2	1,534.4	4,709.5	414.1 [1]
5.	Deferred Rebate Account	2009 DRA	2.7	(0.1)	-	-
6.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	188.7	0.8	2,838.8	- [2]
7.	Ontario Hearing Costs V/A	2009 OHCVA	531.7	0.6	474.5	2.0
8.	Open Bill Service D/A	2009/10 OBSDA	526.2	15.9	87.7	3.0 [3]
9.	Open Bill Access V/A	2009/10 OBAVA	476.7	5.9	79.5	1.2 [3]
10.	Municipal Permit Fees D/A	2009 MPFDA	916.1	-	202.2	- [2]
11.	Average Use True-Up V/A	2009 AUTUVA	5,626.9	5.2	5,626.9	23.4 [4]
12.	Tax Rate and Rule Change V/A	2009 TRRCVA	(350.0)	(0.3)	(350.0)	(1.7) [5]
13.	Earnings Sharing Mechanism D/A	2009 ESMDA	(18,750.0)	(17.2)	(19,300.0)	(77.4) [6]
14.	IFRS Transition Costs D/A	2009 IFRSTCDA	2,111.0	1.9	2,111.0	8.9
15.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	(27.9)	-	(27.9)	(0.1)
16.	Total non commodity related accounts		15,857.5	1,496.4	2,219.4	341.5
	Commodity Related Accounts					
17.	Purchased Gas V/A	2009 PGVA	(116,672.9)	(2,287.8)	(45,275.2)	(2,516.3) [7]
18.	Transactional Services D/A	2009 TSDA	(7,062.1)	(9.5)	(7,062.1)	(31.9)
19.	Unaccounted for Gas V/A	2009 UAFVA	9,596.7	8.8	9,596.7	39.6
20.	Storage and Transportation D/A	2009 S&TDA	(1,594.8)	(4.6)	(1,594.8)	(9.5)
21.	Total commodity related accounts		(115,733.1)	(2,293.1)	(44,335.4)	(2,518.1)
22.	Total Deferral and Variance Accounts		(99,875.6)	(796.7)	(42,116.0)	(2,176.6)

Notes:

1. As approved in EB-2007-0731, the CASDA is to be cleared over 5 years (2008 - 2012). The 2008 installment was cleared in July and August 2008, and the 2009 installment will occur in April and May 2010. The Company now proposes to clear the 2010, or third installment, beginning October 1, 2010. The forecast of interest to be cleared, utilized the Board's current prescribed interest rate for deferral accounts for (Q2 2010) but will be updated with future prescribed rates as well.
2. The forecast 2009 GDARCDA and 2009 MPFDA amounts for clearance are the result of revenue requirement calculations. (Found in evidence at Ex.C, T1, S2 and Ex.C, T1, S3)
3. The forecast OBSDA and OBAVA balances are in accordance with the EB-2009-0043 approved settlement agreement.
4. The AUTUVA explanation is found in evidence at Ex.C, T1, S5.
5. The TRRCVA explanation is found in evidence at Ex.C, T1, S4.
6. The ESMDA explanation is found in evidence at Ex.B, T1, S1&2.
7. This is a final 2009 PGVA principal balance with interest forecast to September 30, 2010.

Witnesses: K. Culbert
D. Small

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 4, page 3 & Exhibit C, Tab 1, Schedule 3, page 6

Please explain why the 2010, 2011 and 2012 tax rates shown on Schedule 4 of 32%, 30.5% and 29% are different from the rates of 31%, 28.25% and 26.25% shown in Schedule 3.

RESPONSE

The 2010, 2011, and 2012 tax rates shown in Exhibit C, Tab 1, Schedule 4, page 3, Row 33 do not include recently legislated changes to provincial income tax rates, whereas the rates shown in Exhibit C, Tab 1, Schedule 3, page 6, Row 29 have been updated accordingly. The Company inadvertently filed original evidence from the EB-2009-0172 proceeding, at page 3, Exhibit C, Tab 1, Schedule 4 of this proceeding, in support of the amount being requested for clearance in the 2009 Tax Rate and Rule Change Variance Account ("TRRCVA"). The Company had intended to file the updated evidence from the EB-2009-0172 proceeding that incorporated the new provincial income tax rates. For reference, updated Exhibit C, Tab 1, Schedule 4, page 4, from EB-2009-0172 is provided on the following page. The Company notes that the amounts being requested for clearance in this proceeding in the 2009 TRRCVA (Exhibit C, Tab 1, Schedule 4) and the 2009 MPFDA (Exhibit C, Tab 1, Schedule 3) were not impacted by this oversight as they were calculated using the correct tax rates.

Witness: K. Culbert

Schedule 1

Updated Summary - Sharing of Tax Change Forecast Amounts

(Incorporates new CCA Class 52, and changes in provincial income and capital tax rates between 2010 and 2012)

Line No.	Tax Related Amounts Forecast from CCA Rate Changes ($ Millions)	Col. 1 2008	Col. 2 2009	Col. 3 2010	Col. 4 2011	Col. 5 2012	Col. 6
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) -**with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	31.00%	28.25%	26.25%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.87%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.94	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	31.11	93.83
37.	Incremental Amount	9.16	1.66	6.43	8.24	5.62	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.80**	
	Tax Related Amounts Forecast from Capital Tax Rate Changes						
39.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
40.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
41.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
42.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
43.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.075%	0.000%	0.000%	
44.	Capital Tax Rate Variance	0.060%	0.060%	0.210%	0.285%	0.285%	
45.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	7.25	9.84	9.84	31.07
46.	Incremental Amount	2.07	0.00	5.18	2.59	0.00	
47.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$2.58**	**$1.30**	**$0.00**	
48.	**Cumulative Total Forecast Tax Related Amount (lines 25+36+45)**	**14.88**	**19.20**	**31.62**	**42.14**	**48.31**	156.16
49.	**Total Incremental Ratepayer Amounts into rates (lines 26+37+46)**	**$7.44**	**$2.16**	**$6.20**	**$5.26**	**$3.08**	
50.	**Total Updated Annual Ratepayer & Company Shareholder Tax Savings (50% of row 48)**	**$7.44**	**$9.60**	**$15.80**	**$21.06**	**$24.14**	$78.04
51.	***Total Original Agreement Annual Ratepayer Tax Savings***	***$7.44***	***$9.25***	***$12.91***	***$18.34***	***$20.91***	*$68.85*
52.	Amount to be credited to 2009 TRRCVA for return to ratpayers ($9.60M - $9.25M) (col.2, line 50 - 51)		$0.35				
53.	Ratepayer share of 2010 incremental tax amounts ($15.80 - $9.25) (col.3, line 50 - col.2, line 51)			6.55			
54.	Ratepayer share of 2011 incremental tax amounts ($21.06M - $15.80M) (col.4, line 50 - col.3, line 50)				$5.26		
55.	Ratepayer share of 2012 incremental tax amounts ($24.14M - $21.06M) (col.5, line 50 - col.4, line 50)					$3.08	

BOMA INTERROGATORY #5

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 2, page 3

a) Has EGD made any changes to the allocations of the various deferral and variance accounts to the rate classes from what has been approved by the Board in the past?

b) If the response to part (a) is yes, please explain the allocation change, the rationale for the change and the impact of the change on the various rate classes.

RESPONSE

a) No, EGD has applied the same allocations to existing deferral and variance accounts consistently with dispositions approved by the Board in the past.

Two new deferral accounts have been approved by the Board for inclusion in 2009. They are the International Financial Reporting Standards Transition Costs Deferral Account (IFRSTCDA) and the Ex-Franchise Third Party Billing Services Deferral Account (EFTPBSDA). The proposed classification and allocation of these accounts by rate class can be found at Exhibit C, Tab 2, Schedule 2 page 3.

b) N/A

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

BOMA INTERROGATORY #6

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 2, page 3

a) In Enbridge's last cost of service application, please indicate how the costs related to income taxes were classified and allocated to the rate classes. Is this consistent with the classification and allocation based on rate base shown on page 3?

b) In Enbridge's last cost of service application, please indicate how the costs related to the return on capital were classified and allocated to the rate classes. Is this consistent with the classification and allocation based on the distribution revenue requirement shown on page 3 for earnings sharing?

c) Please show the impact on each rate class if the earnings sharing were to be classified and allocated based on rate base rather than on the distribution revenue requirement.

RESPONSE

a) The allocation of income tax follows the classification and allocation of the rate base components to the rate classes. The classification and allocation of the 2009 Tax Rate and Rule Change Variance Account balance at Item 18 of page 3 is consistent with the treatment of income taxes as established in the last cost of service application.

b) The allocation of return follows the classification and allocation of the rate base components to the rate classes.

   Please note that the classification and allocation of the 2009 Earnings Sharing Mechanism Variance Account ("ESMVA") balance at Item 19 of page 3 is consistent with the Board-approved methodology of utilizing the distribution revenue requirement as the basis for disposition of the 2008 ESMVA. In this manner, the disposition of the ESMVA balance is consistent with the distribution of rate class costs and the resultant distribution revenues from the various customer classes.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

c) The allocation of the 2009 ESMVA balance to the rate classes is shown on the basis of Distribution Revenue Requirement (DRR) and Rate Base (RB):

Rate Class	Distribution RR *(000s)*	Rate Base *(000s)*
RATE 1	(13,015.6)	(12,991.1)
RATE 6	(5,517.0)	(5,657.8)
RATE 9	(20.1)	(23.0)
RATE 100	(33.7)	(34.5)
RATE 110	(253.5)	(213.9)
RATE 115	(134.4)	(96.1)
RATE 125	(129.5)	(108.1)
RATE 135	(16.2)	(9.1)
RATE 145	(109.9)	(88.8)
RATE 170	(94.0)	(86.9)
RATE 200	(43.5)	(56.2)
RATE 300	(10.0)	(11.9)
TOTAL	(19,377.4)	(19,377.4)

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

CME INTERROGATORY #1

INTERROGATORY

2009 Earnings Sharing Amount

References: Exhibit B, Tab 1, Schedules 1, 2, 3 and 4
Exhibit D, Tab 1, Schedules 1 and 2

The evidence in paragraph 1 of Exhibit B, Tab 1, Schedule 1 states that an analysis of the impact of weather normalization on volumes and gas in storage was conducted following the close of year end processing and that this analysis lead to a revision of the Earnings Sharing calculation contained in the audited Financial Statements for Enbridge Gas Distribution Inc. (“EGD Inc.”) to increase it from $18.75M to $19.3M. Please provide the following information:

(a) The estimates of background information supporting the accrual in the Financial Statements of $18.75M; and

(b) The analysis that was done following the close of year end processing that shows how the impact of weather normalization on volume and gas in storage increased the Earnings Sharing calculation to about $19.3M.

RESPONSE

a & b) As indicated in Ex.B.T1.S1, year end timing obligations sometimes require the use of best estimates. At the time of the accrual of the $18.75M of estimated earnings sharing, an analysis of the impact of weather normalization on gas in storage volumes and related values was not possible and as such, actual gas in storage values supported the year end accrual. Subsequently it was determined that given normal weather, the value of gas in storage would have been approximately $406.5M (Ex.B,T2,S1,p1,col.1,line 10), a reduction of $20.9M from the value of $427.4M included in rate base at the time of the accrual. The following table shows the actual gas in storage values and average of monthly averages used in the determination of the year end accrual of $18.75M in earnings sharing, as well as the revised storage values incorporating the impacts of the weather normalization analysis performed after year end that supports the updated earnings sharing calculation of $19.3M.

Witnesses: K. Culbert
N. Kishinchandani

Table 1.

GAS IN STORAGE
MONTH END BALANCES AND AVERAGE OF MONTHLY AVERAGES
2009 HISTORICAL YEAR

Line No.		Col. 1 Actual EGD Storage Balances Supporting Year End ESM Accrual	Col. 2 Normalized EGD Storage Balances Supporting Updated ESM
		($Millions)	($Millions)
1.	January 1	650.7	650.7
2.	January 31	428.9	424.4
3.	February	367.7	336.0
4.	March	269.4	242.6
5.	April	238.7	200.0
6.	May	266.3	216.7
7.	June	370.8	320.5
8.	July	411.5	381.2
9.	August	485.4	475.2
10.	September	538.5	541.4
11.	October	624.0	612.2
12.	November	606.6	600.9
13.	December	392.4	402.9
14.	Avg. of monthly avgs.	427.4	406.5

Note: The December 2008 normalized gas in storage value was known and used in the year end ESM accrual.

Witnesses: K. Culbert
N. Kishinchandani

CME INTERROGATORY #2

INTERROGATORY

2009 Earnings Sharing Amount

References: Exhibit B, Tab 1, Schedules 1, 2, 3 and 4
Exhibit D, Tab 1, Schedules 1 and 2

The audited Financial Statements at Exhibit D, Tab 1, Schedule 1 indicate that the actual equity ratio for the consolidated entity EGD Inc. at December 31, 2009, was about 28.2%. We derive this actual equity ratio from the total equity for 2009 of $1,967.3M shown in Exhibit D, Tab 1, Schedule 8 by total liabilities of $6,977.8M. At December 31, 2008, the actual equity ratio derived by expressing the 2008 shareholders equity of $1,937.7M as a proportion of the total liabilities of $6,285.1M is about 30.8%. Using these figures, we estimate that, on average, the actual equity ratio of EGD Inc. for 2009 was about 29.5%. Please provide the following information:

(a) Please confirm that the actual average equity ratio for EGD Inc. was about 29.5% for 2009. If EGD Inc. regards that ratio to be incorrect, then please provide EGD Inc.'s calculation of the actual average equity ratio for EGD Inc., the consolidated corporate entity, for 2009.

(b) Please re-calculate the "Required Rate of Return %" of 7.470% shown at line 26 of Exhibit B, Tab 1, Schedule 2 and derived at Exhibit B, Tab 5, Schedule 1, page 1, column 4, line 6 by using the actual average common equity ratio for EGD Inc. for 2009 of 29.5%. In responding to this question, please provide the calculations in Exhibit B, Tab 5, Schedule 1, page 1 using common equity ratio of 29.5% instead of the 36% ratio shown in column 2 at line 5 and increase the short-term debt ratio of 1.66% and costs at line 2 of Exhibit B, Tab 5, Schedule 1, page 1 to reflect a short-term debt ratio of capital structure in an amount of 8.16%, being the sum of 1.66% plus 6.5% which is the amount by which the actual equity ratio of EGD Inc. is less than 36.0%.

(c) Please re-do the Part (A) Earnings calculation in Exhibit B, Tab 1, Schedule 2, page 1 using 29.5% as the "Required Rate of Return %" amount.

(d) Please re-calculate the "Common Equity Amount" shown at line 40 in Exhibit B, Tab 1, Schedule 2, page 1 of $1,366M, derived from Exhibit B, Tab 5, Schedule 1, page 1, column 1, line 5 by multiplying the actual 2009 average

Witnesses: K. Culbert
N. Kishinchandani

equity ratio of 29.5% by the total rate base amount of $3,794.4M shown in line 6, column 1 of Exhibit B, Tab 5, Schedule 1, page 1.

(e) Please provide the calculations in Part (B) of Exhibit B, Tab 1, Schedule 2, page 1 using the 29.5% actual average common equity amount and short-term debt costs at line 35 of Exhibit B, Tab 1, Schedule 2, page 1 based on an 8.16% short-term debt component of capital structure and the cost of short-term debt at 1.66%.

RESPONSE

a) In estimating EGDI's average common equity ratio one cannot use year end point in time information without taking account of certain required adjustments. As examples, adjustments are required for accounting standards changes and other elements which are impacting total liabilities but which do not have any impact on shareholder equity. Recent accounting standards changes noted at Exhibit D, Tab 1, Schedule 1, page 13, required EGDI to include liabilities on its balance sheet which do not impact earnings, cash flows and do not have any corresponding required capital investment or shareholder equity impact. As a result, such liabilities associated with new accounting standards must be adjusted out of any total liability amount which is to be used in estimating any equity investment ratio of EGDI.

The table below shows the adjustments relating to changes in accounting standards which must be made to the liabilities total for the purpose of estimating the year end equity ratio. Also shown is an adjustment relating to the sum of regulatory deferral and variance accounts that do not form part of rate base. While some accounts are capital related and require rate base investment, most in effect do not, these items are typically funded primarily in the form of debt, thus must be removed before evaluating the capital structure.

In addition, in order to determine average equity commensurate with the allowed average rate base one would have to take an average of all of the monthly equity percentages after having accounted for all of the noted required adjustments. EGD has not performed the monthly adjustments and averaging process here as the calculation of the estimated year end equity ratio shown below provides an explanation of why CME's estimated equity and the remainder of the capital structure ratios are inappropriate. As such, the calculations requested in parts b) through e) would produce misinformation and are not provided.

December 31, 2009	$ millions
Total liabilities	6,977.8
Impact of change in accounting standards	(1,133.1)
Non-rate base regulatory items	(336.6)
Adjusted liabilities	5,508.1
Reported equity	1,967.3
Equity as a % of adjusted liabilities	35.7%

Amounts recorded pursuant to adoption of new accounting standards

Pension plans	**205.1**
OPEB	**62.4**
Future removal and site restoration reserves	**691.6**
Future income taxes	**174.0**
	1,133.1

Deferral or Variance Accounts not in Rate Base

Class action lawsuit settlement	**20.4**	Class Action Suit Deferral Account
Ontario hearing costs	**5.6**	Ontario Hearing Costs Variance Account
Purchased gas variance	**226.7**	Purchased Gas Variance Account
Unaccounted for gas variance	**10.2**	Unaccounted for Gas Variance Account
Transactional services deferral	**13.6**	Transactional Services Deferral Account
Demand Side Management variance	**0.9**	Demand Side Management Variance Account
Shared Savings Mechanism	**14.1**	Shared Savings Mechanism Variance Account
Union Gas regulatory deferral	**3.5**	Storage and Transportation Deferral Account
Deferred rebate deferral	**2.1**	Deferred Rebate Account
Gas distribution access rule deferral	**1.0**	Gas Distribution Access Rule Costs Deferral Account
Customer care procurement costs	**2.9**	Not Applicable - amortized over five years to match recovery in rates
CIS procurement and selection costs	**3.1**	Not Applicable - amortized over five years to match recovery in rates
Earnings sharing deferral	**24.4**	Earnings Sharing Mechanism Deferral Account
Tax rate and rule change variance	**0.3**	Tax Rate and Rule Change Variance Account
Average use true-up variance	**2.9**	Average Use True-Up Variance Account
IFRS transition cost deferral	**2.1**	IFRS Transition Costs Deferral Account
Other regulatory assets and liabilities	**2.8**	See note
	336.6	

Note:

Comprised of the following accounts: Lost Revenue Adjustment Mechanism, Manufactured Gas Plant Deferral Account, Open Bill Service Deferral Account, Open Bill Access Variance Account, Unbundled Rates Customer Migration Variance Account, and other miscellaneous deferred amounts.

Witnesses: K. Culbert
N. Kishinchandani

CME INTERROGATORY #3

INTERROGATORY

Unregulated Storage Revenues and Costs

References: Exhibit B, Tab 1, Schedule 4, pages 2 and 3, item (c), (d), (e) and (g)
Exhibit D, Tab 1, Schedule 2, pages 5 and 6

The evidence indicates that one of the causes for 2009 over 2008 increases in "Other Revenue" for the consolidated entity, EGD Inc., was revenue from the unregulated storage business. The evidence indicates that the company expanded its storage capacity by 6% to sell unregulated storage services into the storage market and that additional storage expansion for this purpose is planned to be in service in 2010. Please provide the following information:

(a) All capital expenditures incurred by EGD Inc. to December 31, 2009, to expand its storage capacity by 6%.

(b) The 2009 carrying costs on these incremental expenditures using the capital structure and costs shown in Exhibit B, Tab 5, Schedule 1, page 1.

(c) A description of all other storage assets that are partially used to support the provision of unregulated storage services, along with the carrying costs incurred to support those assets and the manner in which responsibility for a portion of those costs has been allocated to the unregulated storage business.

(d) Please provide the total 2009 Costs of Service, excluding return, related to both the incremental assets and commonly used assets that support the provision of unregulated storage services and include a description of the method used to allocate such Costs of Service associated with the commonly used assets to the unregulated storage business.

(e) Please provide the amount of 2009 unregulated storage revenues that were excluded for the purposes of determining 2009 utility earnings and the ratepayers share thereof.

Witnesses: K. Culbert
N. Kishinchandani
J. Sanders

RESPONSE

a) Enbridge Gas Distribution Inc. is not prepared to disclose information related to the capital expenditures incurred with the development of unregulated storage assets and details of the resulting revenues for the period up to December 31, 2009. All public information related to the unregulated storage business will be made available consistent with EB-2008-0052, the Storage and Transmission Access Rule.

b) See (a)

c) As was recognized and understood throughout the NGEIR proceeding, EB-2005-0551, and the resulting decision, unregulated storage services have been developed through the addition and integration of new facilities with the pre-existing storage facilities that had been owned and/or operated by Enbridge prior to 2007.

   The capacities that support both the regulated and unregulated storage services now result from the operation of these integrated facilities, however, it is clear that the incremental storage capacity that has been created over this period is attributable to the incremental facilities that have been constructed during and after 2007.

   As per the findings and decision of the NGEIR proceeding, the allocation of Enbridge's pre-existing storage assets is one hundred percent to regulated, utility storage and zero percent to unregulated storage. All of the costs of the incremental storage facilities constructed since that Decision have been charged to the separate accounts of Enbridge's unregulated storage activity.

d) The cost of general storage operations charged to the unregulated storage activity in 2009 were derived using a cost allocation based upon the relative shares of total gas storage capacity that were held by the regulated and unregulated activities. That allocation exercise incorporated all gas storage operating and maintenance costs including labour and materials, contractor and consultant costs and such items as hydro and land rights rental costs. It also included the allocation of EGDI corporate overheads to the unregulated storage activity. In addition, any direct and dedicated costs were captured completely by the unregulated storage business.

   For many of these cost categories, there has been little or no cost increase to the integrated operation caused by the operation of the incremental storage capacity. Costs such as operating labour, training and land rights have changed little, or not at all, with the addition of these new capacities. However, using this allocation method, a portion of those costs have been charged to the unregulated storage operation and credited to the regulated operation. The effect of this has been that the net costs to the regulated storage operation in 2009 were lower than they would have been had the unregulated operation not existed.

e) See (a)

Witnesses: K. Culbert
N. Kishinchandani
J. Sanders

CME INTERROGATORY #4

INTERROGATORY

Deferral and Variance Account Clearance on October 1, 2010

References: Exhibit A, Tab 3, Schedule 1
Exhibit C, Tab 1, Schedule 1
Exhibit C, Tab 2, Schedule 2, page 2

The evidence indicates that, because of testing and analysis with respect to the implementation of the Harmonized Sales Tax ("HST"), any increments to the balances recorded in 2009 Deferral Accounts after February 28, 2010, will not be cleared on October 1, 2010, but at some, as yet, unspecified date. In connection with this proposal, please provide the following information:

(a) When does EGD Inc. propose to clear amounts recorded in 2009 Deferral Accounts after February 28, 2010?

(b) Can EGD Inc. provide forecasts of balances that will likely be recorded in these accounts between March 1, 2010, and June 30, 2010, so that these forecasted amounts could be included in the amounts to be cleared on or about October 1, 2010?

(c) Would it not be better to clear July 1, 2010, forecast balances on October 1, 2010, rather than allowing four (4) months of further accumulations to be cleared sometime thereafter?

(d) What are the HST implications of clearing deferral account amounts recorded prior to July 1, 2010, on a date after July 1, 2010? Will the amounts attract GST based on the date of their clearance and regardless of whether they were incurred and recorded before July 1, 2010?

RESPONSE

a) The evidence at Exhibit A, Tab 3, Schedule 1, paragraph 1 b) states that attempting to clear the accounts at July 1, 2010, could pose complications due to testing and implementation of HST on July 1, 2010 and as a result the Company has proposed all accounts be cleared on October 1, 2010.

Witnesses: K. Culbert
D. Small

b) Other than finalization of the PGVA account and closing true up balance, there are no forecast additions to any of the accounts for 2009 other than the continuation of interest accruals as prescribed in the approved account descriptions.

c) As indicated in part a), EGD has proposed clearance of the accounts on October 1, 2010.

d) The account amounts, due to their accumulation prior to July 1, 2010, will not attract total HST impact upon clearance in October, 2010 but rather will only attract GST impacts. As the total of the accounts is a credit, there will be a reduction in the total amount of GST that otherwise would have been included on customers' bills in October.

Witnesses: K. Culbert
D. Small

CME INTERROGATORY #5

INTERROGATORY

Reconciliation of Regulatory Deferral Account Balances with Financial Statements Amounts

References: Exhibit C, Tab 1, Schedule 1, page 2
Exhibit D, Tab 1, Schedule 1, page 16

The Financial Statements show amounts for various deferral and variance accounts pertaining to the utility that differ from the amounts shown in column 1 of Exhibit C, Tab 1, Schedule 1, at page 2. Please provide the following information:

(a) A reconciliation of each of the actual balances shown in column 1 of Exhibit C, Tab 1, Schedule 1 at page 2 with the amounts shown for each of these deferral accounts for 2009 in the Consolidated Financial Statements for EGD Inc. at Exhibit D, Tab 1, Schedule 1, page 16.

RESPONSE

Please refer to the response to SEC Interrogatory #7b (Exhibit I, Tab 5, Schedule 7) which provides a breakdown of the amounts contained in Exhibit D, Tab 1, Schedule 1, page 16, that can be used to reconcile to the amounts contained in Exhibit C, Tab 1, Schedule 1, page 2. It should be noted that a comparison between these two exhibits will not yield identical results as the lists are for different accounts as of different dates.

Witnesses: K. Culbert
N. Kishinchandani
D. Small

CME INTERROGATORY #6

INTERROGATORY

Gas Distribution Access Rule ("GDAR") Deferral Account

Reference: Exhibit C, Tab 1, Schedule 2

It is proposed that a revenue requirement/cost of service type of calculation be used to collect the capital and operating expense amounts recorded in this deferral account. The costs of debt used in the calculation are 7.31% for long-term and 4.12% for short-term, being rates that exceed the rates shown in Exhibit B, Tab 5, Schedule 1 of 6.90% for long and medium-term debt and 1.66% for short-term debt. For preference shares, the rate used is 5% compared to the 3.35% shown in Exhibit B, Tab 5, Schedule 1, page 1. For equity, the return is 8.39% rather than 8.31% shown in Exhibit B, Tab 5, Schedule 3, page 1, line 12. As well, the components of the capital structure used in the revenue requirement calculation pertaining to amounts recorded in this deferral account differ from the components of capital structure shown in Exhibit B, Tab 5, Schedule 1, page 1. Please provide the following information:

(a) Please explain why cost of capital rates that differ form those shown in Exhibit D, Tab 5, Schedule 1 are used in this revenue requirement calculation.

(b) Please explain the derivation of the depreciation rate that is being used in the calculation.

(c) Please calculate the amount recoverable if the carrying costs on the amounts of capital expenditure from ratepayers are limited to a 50/50 mix of long and short-term debt capital and exclude any equity and preference share return and related income taxes.

RESPONSE

a) The cost of capital rates used within the GDAR revenue requirement calculation, require the use of a Board Approved capital structure. The use of the 2007 approved capital structure is consistent with the Board's approval of the previous years Board Approved GDAR revenue requirement.

Witness: K. Culbert

b) The GDAR revenue requirement includes computer software spending and as such, the Company's most recent approved depreciation rate for computer software, 20%, is the rate being used in the GDAR revenue requirement. Again, this is consistent with the manner in which previously approved GDAR revenue requirement amounts were determined.

c) GDAR required asset related spending, specifically for computer software, by EGD. The result is that a capital investment is required by EGD and as such the carrying costs required in relation to GDAR cannot exclude equity, preference shares or income taxes. It is inappropriate to assume any alternate mix of capital funds as being available for GDAR other than the entire required capital structure. As a result the calculations requested are meaningless and have not been provided.

CME INTERROGATORY #7

INTERROGATORY

Municipal Permit Fees Deferral Account

Reference: Exhibit C, Tab 1, Schedule 3, page 1

A revenue requirement/cost of service type of calculation is also proposed to recover costs recorded in this deferral account. Please provide the following information:

(a) The depreciation rate being used with respect to this account.

(b) A calculation similar to the calculation requested in Question 6 (c) that limits recovery from ratepayers to costs associated with a 50/50 mix of long and shortterm debt capital and excludes any return associated with preference and equity capital and related income taxes.

RESPONSE

a) The asset and depreciation rate used within this account is plastic mains with a depreciation rate of 4.39%, which is the most recent approved depreciation rate for this asset category.

b) This information is not being provided for the same reasons provided in response to CME Interrogatory #6 at Exhibit I, Tab 3, Schedule 6.

Witness: K. Culbert

CME INTERROGATORY #8

INTERROGATORY

2009 Actual Average Use True-Up Variance Account

Reference: Exhibit C, Tab 1, Schedule 5

Please advise whether the amounts recorded in this variance account are limited to the effects of conservation or whether they also capture the impacts on actual average uses of all events other than weather.

RESPONSE

As stated in paragraph 8 at Exhibit C, Tab 1, Schedule 5 and in accordance with the Settlement Agreement filed at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, the purpose of the Average Use True-Up Variance Account ("AUTUVA") is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer embedded in the volume forecast and the actual weather normalized average use experienced during the year for Rate 1 and Rate 6 customers, excluding the volumetric impact of Demand Side Management programs in that year.

As a result, the amounts recorded in this variance account will only capture the revenue impact of the volumetric variance between forecast average use and actual weather normalized average use for those drivers other than weather and Demand Side Management programs.

Witness: I. Chan

CME INTERROGATORY #9

INTERROGATORY

2009 Actual Average Use True-Up Variance Account

Reference: Exhibit C, Tab 1, Schedule 5

Please estimate the recoverable amount if the effects of this variance account are limited in scope to conservation only.

RESPONSE

The reported variance amounts for Rate 1 customers of $2.5 million or 36 10^6m^3 (0.8% of total weather normalized actual consumption in the amount of 4,533.8 10^6m^3 found at Appendix A, Table 4, Item 1.1 in Col. 13) on page 1 at Exhibit C, Tab 1, Schedule 5, Appendix A, are all conservation related.

As stated in evidence in the 2009 rate adjustment proceeding EB-2008-0219, at Exhibit C, Tab 2, Schedule 3, page 18, the major driver variables in residential average use are weather, vintage, time trend, real energy prices and economic variables. Please refer to Appendix A which provides evidence that was originally filed in EB-2008-0219, at Exhibit C, Tab 2, Schedule 3, for a description of how the driver variables identified above can reduce energy consumption (at pages 18 to 20). These drivers include purchasing a new house, new appliance, replacing an old appliance with a new and efficient one, embracing conservation programs initiated by governments, renovating the house, lowering the thermostat settings.

Other than the unexpected net rate switching losses from general service Rate 6 to contract rate (or transfer losses) of $2.8 million (or 74.5 10^6m^3) as reported at Exhibit C, Tab 1, Schedule 5, on page 2, the amount relating to conservation for Rate 6 customers is $0.3 million or 6.7 10^6m^3. Please refer to Appendix B which provides evidence that was originally filed in EB-2008-0219 at Exhibit B, Tab 1, Schedule 5, pages 11 to 18, for an explanation of the rationale behind this migration trend, which is always volatile and unpredictable. For example, in the 2009 historical year, unanticipated rate switching from the contract market to general service Rate 6 resulted in net transfer gain of $4.16 million (103.9 10^6m^3) as mentioned in Exhibit C, Tab 1, Schedule 5, on page 2.

Further, please refer to the response to CME Interrogatory #8 filed at Exhibit I, Tab 3, Schedule 8 for a description of the methodology governing the use of the Average Use True Up VA (AUTUVA).

Witness: I. Chan

14. Driver variable assumptions are presented in Table 10 in year over year growth rates. Major driver variables in the model include balance point heating degree days adjusted for billing cycles, vintage, time trend, real energy prices and economic variables. Driver variable assumptions are based on economic assumptions from the Economic Outlook, Spring 2008.

15. Higher natural gas prices have a negative impact on average use. Sharp increases will have two effects. First, it will cause customers to change their fuel use habits, for example, by lowering thermostat settings. Second, price increases will likely cause customers to purchase more efficient furnaces and other appliances. In addition, homeowners could retrofit older residences in order to reduce their energy consumption. Real energy prices are used in the model. The Consumer Price Index ("CPI") is used to convert nominal gas prices to real gas prices. Nominal energy price forecasts are based on the Fekete's price forecast produced in April 2008.

16. A linear time trend is used as a proxy measure for energy conservation. However, a linear time trend only reflects constant annual changes in appliance efficiency; it will not be able to reflect the time varying impact of new residential construction on appliance efficiency. Consequently, a vintage variable serves as either a supplementary or complementary variable to the time trend in the model.

17. The vintage variable (for revenue class 20 only) is employed as a proxy measure of gas space heating and gas water heating efficiency gains and residential thermal efficiency. Newer homes with improved thermal envelope characteristics and older homes adding insulation and storm windows/doors reduce the typical amount of gas needed for space heating. Residential thermal efficiency will continue to

improve as newer, better-insulated residences account for a larger portion of the housing stock. The vintage variable captures the impact of both furnace efficiency and new home thermal efficiency on average use.

18. Vintage is defined as the fiscal year in which the customer became a customer (new gas service main date) and is not based on the age of the building. This data includes both new construction and conversion customer additions. As space heating efficiency gains have a greater impact on average use than thermal improvements to homes, customers by vintage is a better variable than age of the building in terms of explaining the percentage decline in residential average use.

19. An illustration of the vintage ratio for 1992 follows:

$$V_{1992} = \frac{\sum_{y=1987}^{1991} V_y}{\sum_{yy=1987}^{1992} V_{yy}} \quad \text{where } V \text{ denotes vintage.}$$

20. Fiscal 1991 is used as the reference year for the vintage ratio since the Energy Efficiency Act prohibited selling of the conventional low-efficiency furnace in January 1992.[7] Consequently, this ratio will capture the increasing market share of both mid-efficiency and high-efficiency furnaces at the expense of declining market share of conventional furnaces over time. Table 10 shows that regions with stronger new construction additions, such as Western and Northern, experience a sharper decline in the ratio than established regions like Metro. As more new

[7] During the 1970s natural gas furnaces averages about 65% Annual fuel Utilization Efficiency ("AFUE"). The Energy Efficiency Act, imposed 78 % AFUE as a minimum for gas furnaces manufactured after January 1, 1992.

customers are added to the revenue class the declining ratio leads to lower average use over time. Thus the sign of this variable's coefficient is positive.

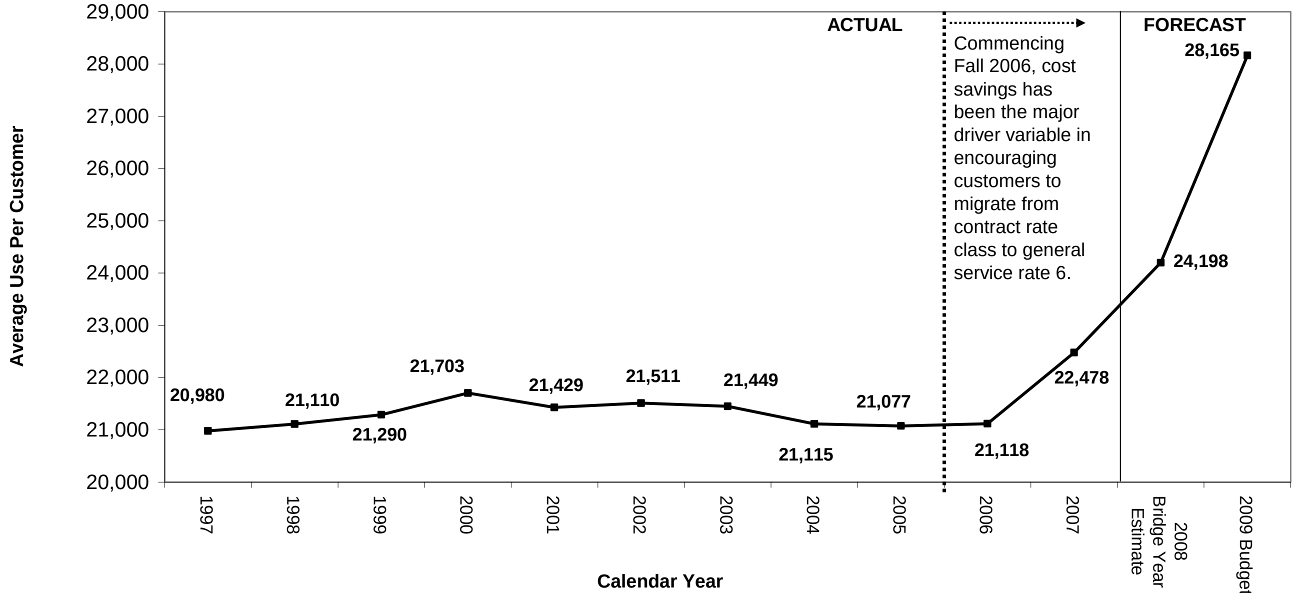
21. Economic variables such as employment, vacancy rates and gross domestic product can impact demand for new gas appliances as well as impact demand for natural gas for space heating and manufacturing processes. Stronger employment and demand for products both domestically and abroad will generally increase natural gas demand.

which can displace natural gas water heater usage in the future. As there is insufficient information available from the Government of Ontario in order to apply the estimated energy savings of these green technologies, the risk of incurring larger residential volume loss than budgeted is weighted heavily to the downside.

20. Rate 6 is comprised of the apartment, commercial, and industrial sectors. From 1997 to 2007, normalized Rate 6 average use has increased by an average of 150 m^3 or 0.7% per year. The increase in 2007 actual usage is largely attributable to the rate switching from contract customers to general service customers starting in the fall of 2006. The anticipated continuation of this trend is the primary reason for the dramatic surge in 2009 of Rate 6 average use budget numbers. Further explanation about this rate switching trend will be presented later.

21. Figure 2 below shows the Rate 6 average use from 1997 to the 2009 Test Year on a test year weather normalized basis, as filed at Appendix A, page 21. Excluding the rate switching, impacted by new factors that are much higher than the historical trend, during the high and volatile natural gas price period between 2001 and 2006, normalized Rate 6 average use has decreased by an average of 98.0 m^3 or 0.45% per year. With the current volatile and unpredictable migration trend, an average use factor that is solely based upon general service rate class is quite misleading when the total volume is in fact unchanged, all else being equal.

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



22. As in the past trends in all of the Rate 6 sectors have been variable over time. Economic conditions and rate switching have always played a significant role in these sectors' average uses in addition to other similar factors that are impacting residential average uses. Rate 6 (general service rates) or contract customers often switch between rate classes or gas service plan types conditional upon if customers are reasonably assured of meeting the minimum required volumes of 340,000 m^3 for requesting Large Volume contracts.

23. Customers typically sign a contract for one year, and the customer is made aware of the minimum bill penalties if the total consumption is below 340,000 m^3. Every year, account executives will review contracts with customers. If customers' prior year or future years' consumption does not meet the minimum threshold requirement, customers would opt for switching to general service rates in order to

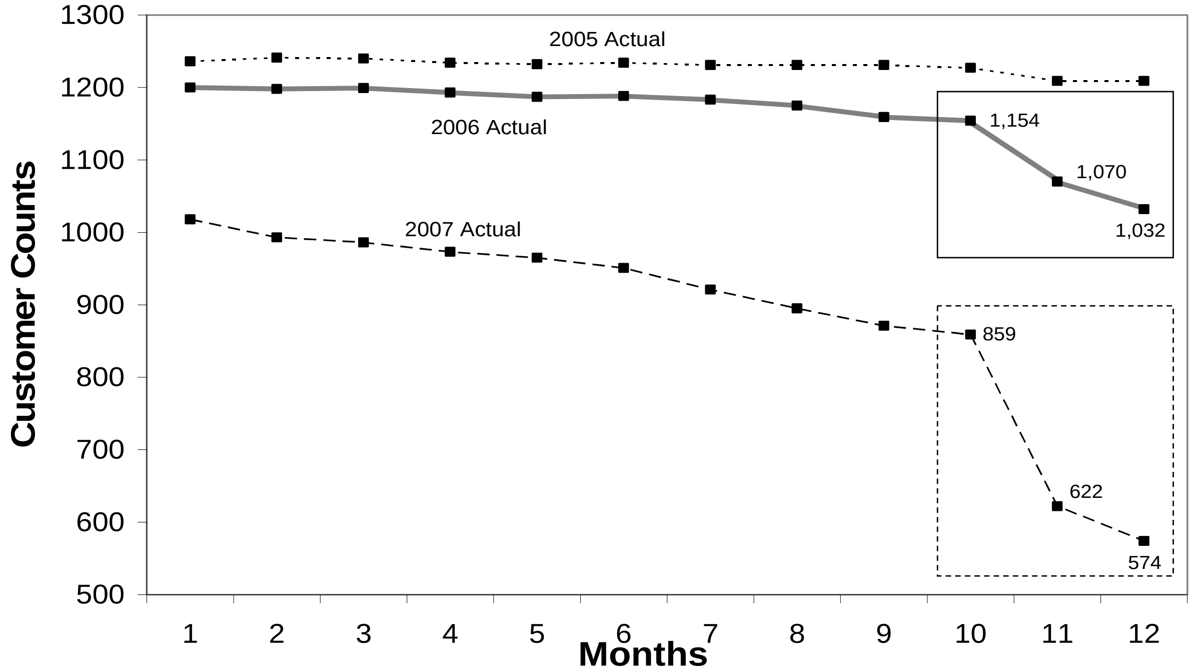
Witnesses: I. Chan
T. Ladanyi

avoid paying the minimum bill penalties. There are a number of reasons that the customers may not meet the minimum threshold, such as higher vacancy rates, warmer weather, customers embracing DSM or conservation initiatives, winding down industrial production, changes in production process to enhance efficiency, plant consolidation and fluctuation in product demand.

24. In addition to the factors mentioned above, the rate switching trend has been increased by new factors starting in the fall of 2006 as mentioned in the response to an Undertaking at EB-2006-0034, Exhibit J4.10 and 2008 Gas Volume Budget Evidence at EB-2007-0615, Exhibit C, Tab 2, Schedule 2. These new factors are the introduction and enforcement of new large volume contracts along with Appendix A of the Company's Rate Handbook for each terminal location during 2006 as well as the rate design change for Rates 100 and 145 by requesting them to pay contract demand charges effective April 1, 2007.

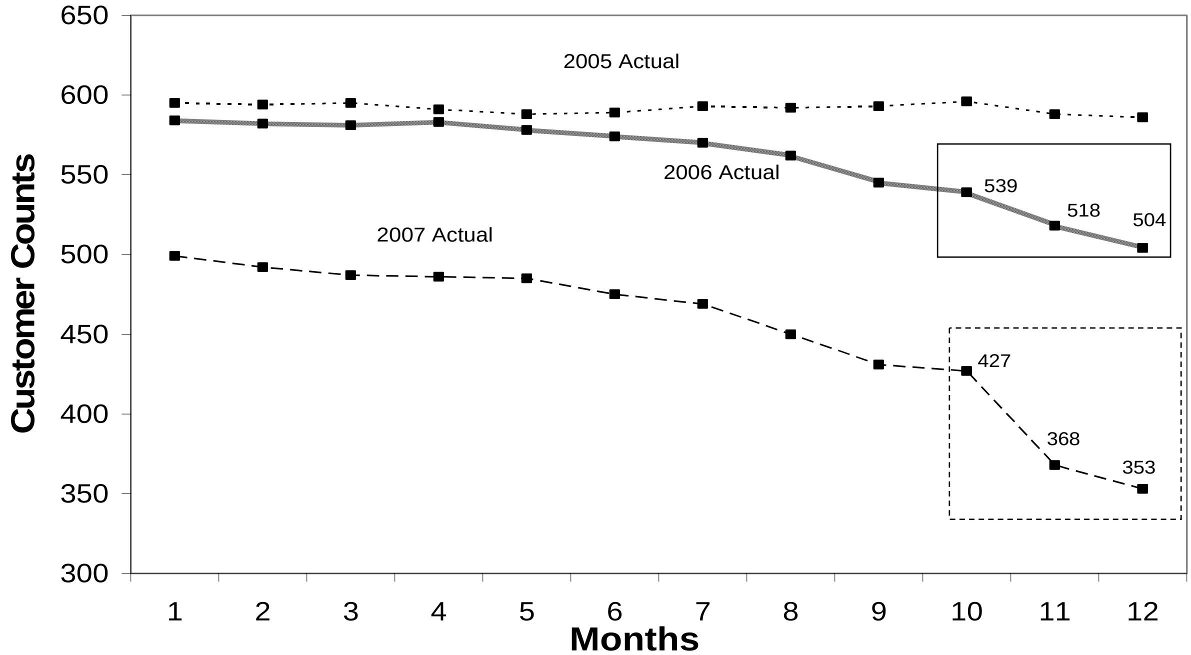
25. In the past, large volume distribution contracts were not signed by the customers themselves as they were covered off under the Gas Transportation Agreements. Similarly, Rates 100 and 145 customers did not need to pay contract demand charges. In addition to these new factors, the phase-in changes to the upstream cost allocation since October 2004 and the rate redesign of Rate 6 in 2004 have been gradually reducing the cost difference between general service and contract rate classes for some customers. As a result, these changes also helped to increase the rate switching trend experienced during years 2006 to 2008. Figures 3 to 5 on the next several pages illustrate the occurrence of historic-high rate switching from contract rate class to Rate 6 during the contract renewal period since the fall of 2006.

Figure 3: Contract Market Unlock Customers
Apartment Sector



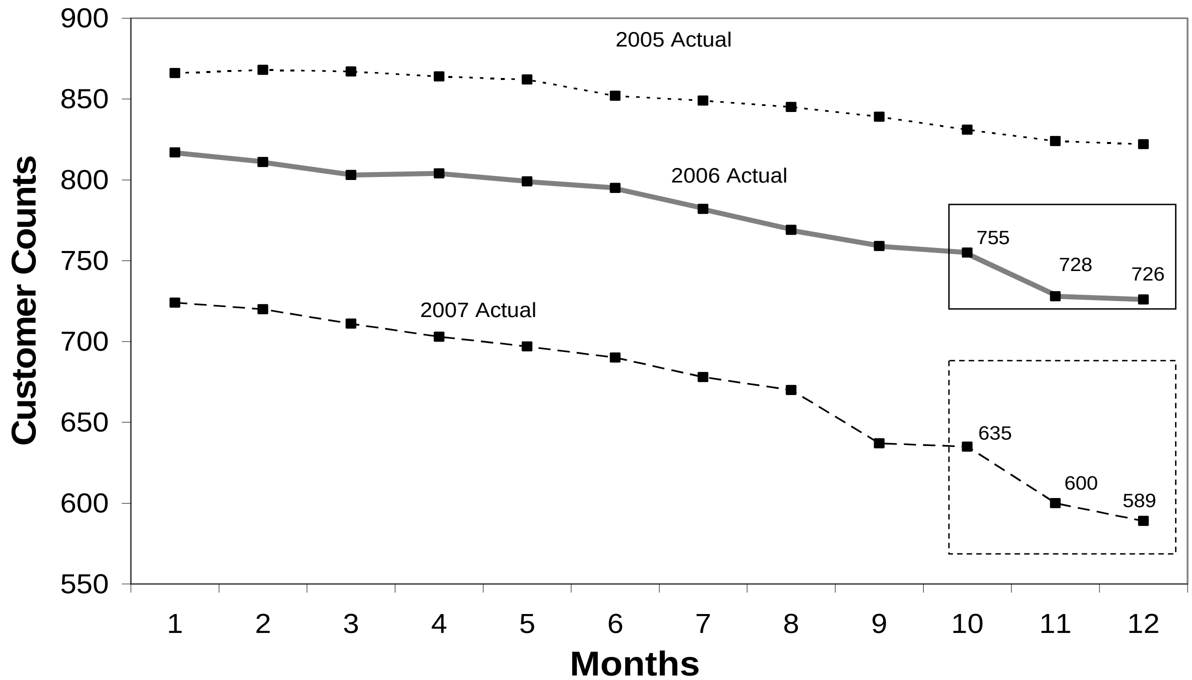
Witnesses: I. Chan
T. Ladanyi

**Figure 4: Contract Market Unlock Customers
Commercial Sector**



Witnesses: I. Chan
T. Ladanyi

Figure 5: Contract Market Unlock Customers
Industrial Sector



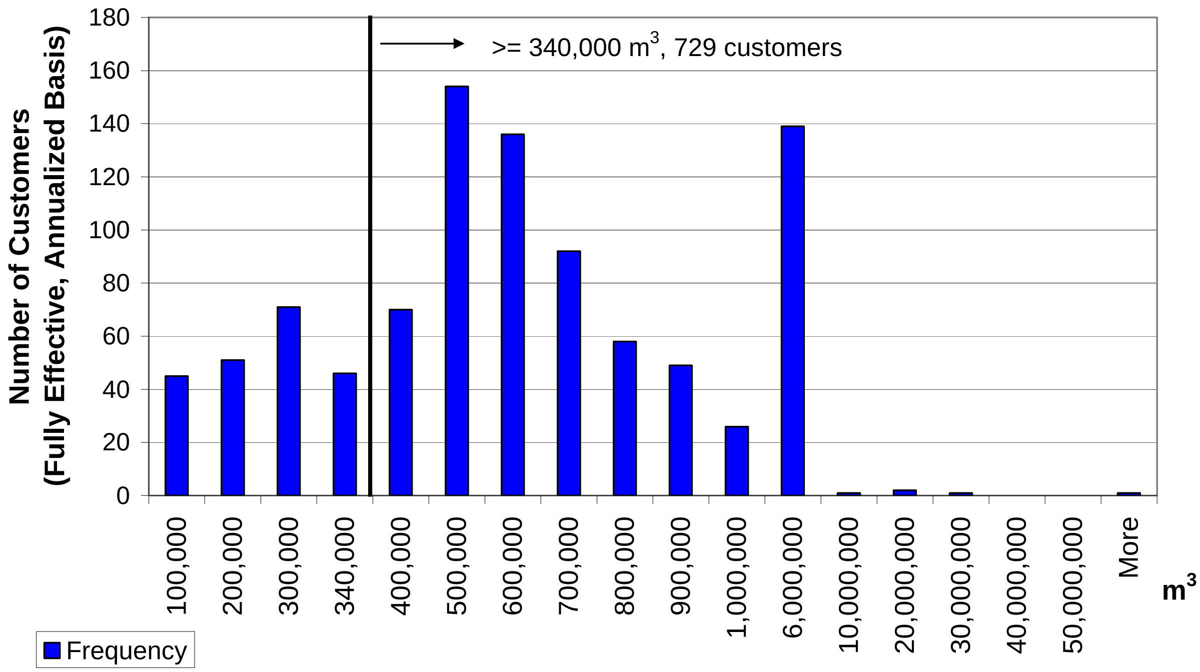
26. Over and above the factors mentioned above, another change to the rate design that was accepted in the Incentive Regulation Settlement Agreement at EB-2007-0615, Exhibit N1, Tab 1, Schedule 1, pages 33 and 34 and was not known when preparing 2008 Volume Budget, has further diminished the cost difference between general service and contract rate classes for remaining contract customers. Specifically, this rate design change reflects the implementation of increasing monthly customer charges for Rate 1 and Rate 6 on a revenue neutral basis by reducing variable charges accordingly and increasing both fixed and variable charges for other rate classes. Consequently, all existing Rate 100 customers will experience a reduction in rate impact by migrating from Rate 100 to Rate 6. In addition, these customers will no longer have to incur monthly fixed contract demand charges and minimum bill penalties in the situation of consuming gas less

Witnesses: I. Chan
T. Ladanyi

than their forecast or contracted volumes. This is especially important to customers who are currently facing volatile and unfavourable business environments.

27. For instance, Figure 6 below displays one Rate 100 contract of 27.1 10^6m^3 and one Rate 110 contract of 51.3 10^6m^3 of two large auto customers who will migrate to Rate 6 effective September 2008 and January 2009, respectively. This migration will not only enable them to reduce energy expenses but will also help them to avoid paying either minimum bill penalties or monthly fixed contract demand charges when the plant is idle or during reduced production as experienced over the past three years.

Figure 6
Customer Migration from Contract Rate Class
(i.e. > Rate 100) to General Service Rate 6 in 2009 = 722.8 10^6m^3



Witnesses: I. Chan
T. Ladanyi

28. The reason why these new rate switching factors are different from the previous years is that the rate switching that occurred in the past was primarily as a consequence of customers not meeting the annual threshold volume of 340,000 $m^{3.}$ The reason behind recent years' switching is that customers are receiving the financial benefits of migrating from their existing contract rate classes to general service Rate 6 even though their annual volume exceeds the volume threshold mentioned above. Figure 6 above presents the frequency distribution of the customers that are forecast to migrate from contract rate classes to general service Rate 6 (transfer gain only) between the 2009 Budget and the 2008 Bridge Year Estimate. Holding all other things constant, this increases the Rate 6 average use considerably as most of these customers consume more than 340,000 m^3 annually.

29. Based upon historical actual data to 2007, the regression model will not be able to predict the 2009 Budget rate switching for a heterogeneous customer mix that has different individual usage pattern as discussed above. Therefore, both the 2008 estimate and the 2009 budget volumes for these contract customers are layered onto the regression model's average use forecast.

30. Tables 4 to 6 on the next several pages quantify the volumetric impact of the average use's driver variables on the apartment, commercial and industrial sector's average use forecast and customer growth, respectively. On a weather-normalized basis, the increase in the Rate 6 volumes of 712.5 10^6m^3 is in consequence of rate switching from contract market customers, positive customer and employment growth, partially offset by the Company's DSM initiatives, other conservation initiatives originated by customers themselves or promoted by government programs and higher gas prices in 2009 than in 2008.

Witnesses: I. Chan
T. Ladanyi

CME INTERROGATORY #10

INTERROGATORY

Ontario Hearing Costs Variance Account

Reference: Exhibit C, Tab 1, Schedule 6, page 1

In connection with the amounts shown at lines 1, 4, 10, 11, 12, 13, 14 and 15 of Exhibit C, Tab 1, Schedule 6, page 1, please provide the following information:

(a) A complete list of all of the expenditures reflected in each of the line items.

(b) Where the expenditures involve amounts paid to professional services advisers, including lawyers and consultants, the name of the service provider, the hourly rate paid, and the estimated total number of hours covered by these expenditures.

RESPONSE

a & b) The following table provides further details of the amounts contained in the requested lines, from Exhibit C, Tab 1, Schedule 6.

In addition, by letters dated April 27 and 28, 2010 from Shibley Righton LLP, the Company received two invoices for unbilled time incurred by Mr. Shepherd on behalf of the School Energy Coalition ("SEC") in respect of participation in the corporate cost allocation consultative in 2008 and 2009 and participation and service on the DSM consultative, evaluation and audit committee over the years 2005 to 2009. Copies of the Shibley Righton letters and supporting invoices and dockets are attached. The aggregate of the invoices received total $67,421.40. The Company has been advised that a cost claim for the subject time was not advanced earlier through inadvertence.

The Company has reviewed these cost claims and has determined that Mr. Shepherd did participate at the relevant times. The Company has also determined that it did not receive an earlier cost claim from Mr. Shepherd on behalf of SEC for his work on these various committees.

Witness: K. Culbert

Upon review of the dockets, it appeared that some of the time entries did not relate to either the corporate cost allocation consultative or to DSM matters. Accordingly, Mr. Shepherd was asked to carefully review his dockets and confirm the nature of the time expended and the appropriateness of the cost claim. By a letter dated May 24, 2010 (copy attached) Mr. Shepherd responded advising that certain entries had been inappropriately included by Shibley Righton in the invoices. Mr. Shepherd also adjusted the hourly rate to reflect the amount permitted under the Board's Cost Guidelines at relevant times. As a result of Mr. Shepherd's review and hourly rate adjustment, the total cost claim was reduced to $61,658.10 consisting of a claim of $4,762.80 for the corporate cost allocation consultative work and $56,895.30 in respect of DSM committee matters (all figures include GST).

The Company proposes to add these amounts to the 2009 Ontario Hearing Costs Variance Account for recovery, within an evidence update.

Table 1

Exh. C, T1, S6 Line No.			Total Costs ($000's)	Average Hourly Rate	Description
1.	Legal				
	Aird & Berlis		$ 551.0	varies[1]	Legal fees for annual rate proceedings, related and general matters.
4.	Consultants				
	Black and Veatch Canada	$ 73.3		varies[2]	System reliability issue
	ICF International	31.9		varies[3]	IPSP proceeding (Costs shared with Union)
	Elenchus Research Assoc.	53.5		varies[4]	RCAM consultation process
	Regulatory Support Services (R.J. Betts)	53.9		varies[5]	Facilitate system reliability and storage unbundling consultatives & other
	Concentric Energy Advisors Inc.	62.9		varies[6]	OEB Cost of Capital proceeding (EB-2009-0084)
			275.5		
10.	EB-2009-0084 OEB Cost of Capital Consultative				
	Aird & Berlis	174.5		varies[1]	Legal fees
	The Brattle Group	24.1		varies[7]	Consulting services
	Concentric Energy Advisors Inc.	387.8		varies[6]	Consulting services
	Donald Carmichael	25.0		n/a[8]	Consulting services
			611.4		
11.	EB-2008-0408 OEB IFRS Consultative				
	Aird & Berlis	40.7		varies[1]	Legal fees
	OEB	140.3		n/a	OEB costs plus intervenor costs remitted to the Board
	EGDI Employee exp a/c	0.1		n/a	
			181.1		
12.	CIS & Open Bill Consultatives				
	Borden Ladner Gervais LLP	3.1		varies	CIS Consultative
	Shibley Righton LLP	4.9		varies	CIS Consultative
	Aird & Berlis	120.6		varies[1]	Legal fees - Open Bill Access consultative and proceeding
			128.6		
13.	DSM Clearance Application & Consultative				
	Aird & Berlis	49.3		varies[1]	Legal fees - DSM guidelines consultation, input assumptions, & def. clearance
	Borden Ladner Gervais	9.1		varies	DSM Input Assumptions EB-2008-0384 / EB-2009-0103
	David Poch	3.5		varies	DSM Input Assumptions EB-2008-0384 / EB-2009-0103
	Energy Probe	3.5		varies	DSM Input Assumptions EB-2008-0384 / EB-2009-0103
	Macleod Dixon	2.9		varies	DSM Input Assumptions EB-2008-0384 / EB-2009-0103
	Shibley Righton LLP	1.6		varies	DSM Input Assumptions EB-2008-0384 / EB-2009-0103
			69.9		
14.	Consultation on Energy Issues / Low Income Consumers				
	Aird & Berlis	0.5		varies[1]	Legal fees
	OEB	44.5		n/a	OEB costs plus intervenor costs remitted to the Board
			45.0		
15.	Gas Storage Allocation / other Consultative				
	Aird & Berlis	4.9		varies[1]	Legal fees - STAR, RCAM consultative, Garland
	Association of Physical Plant Administrators	1.4		varies	Storage Unbundling & Upstream Transportation consultatives
	Borden Ladner Gervais	1.3		varies	RCAM Consultative
			7.6		
	Sub-total		1,870.1		
2.	Intervenor Costs		361.3		2009 Rate Case, 2008 ESM, QRAM, and other
3.	Ontario Energy Board		3,960.3		
5.	Transcripts, newspaper notices, printing, other		182.5		
				Threshold	OHCVA
	Total Ontario hearing costs as per Exh. C, T1, S6		6,374.2	5,842.5	531.7
	Outstanding Shibley Righton LLP (SEC) costs		61.7		
				Threshold	OHCVA
	Proposed revised total Ontario hearing costs		6,435.9	5,842.5	593.4

Notes:
1) Hourly rates range from $425/hr to $625/hr before incorporating a graduated discount ranging from 10-15%.
2) Hourly rates range from $280 U.S./hr to $325 U.S./hr.
3) Hourly rates range from $140 U.S./hr to $280 U.S./hr.
4) Total fees result from the combination of per diem and hourly rates, resulting in an hourly range of $175/hr to $375/hr.
5) Total fees result from the combination of per diem and hourly rates, resulting in an hourly range of $160/hr to $300/hr.
6) Hourly rates range from $50 U.S./hr to $475 U.S./hr.
7) Hourly rates range from $200 U.S./hr to $550 U.S./hr.
8) Flat fee.

SHIBLEY RIGHTON LLP
Barristers and Solicitors

TORONTO OFFICE:
250 University Avenue, Suite 700, Toronto, Ontario, M5H 3E5
Main 416 214-5200 Toll free 1-877-214-5200
Facsimile 416 214-5400

WINDSOR OFFICE:
2510 Ouellette Avenue, Suite 301, Windsor, Ontario, N8X 1L4
Main 519 969-9844 Toll free 1-866-422-7988
Facsimile 519 969-8045

www.shibleyrighton.com

Please reply to the TORONTO OFFICE

Sandra E. Dawe
Direct Line 416-214-5481
Direct Fax 416-214-5482
sandra.dawe@shibleyrighton.com

April 27, 2010

File No. 2080708

Director, Regulatory Affairs
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, ON M2J 1P8

Dear Mr. ~~Ryckman~~: Lorraine Chiasson

Re: Enbridge Corporate Cost Allocation Consultation

As you may be aware, Mr. Shepherd is no longer practicing at this firm. Upon reviewing the file we have noticed that there is a outstanding claim for work done in the period from October 2008 to December 2009. Please find enclosed our claim which we trust you will find satisfactory. Please make payment by cheque payable to Shibley Righton LLP In Trust.

Should you have any questions or concerns, please do not hesitate to contact the undersigned.

Yours truly,

SHIBLEY RIGHTON LLP

Sandra E. Dawe
SED/tw
Enclosures 2

FORM 1

Appendix "B"

SUMMARY STATEMENT OF HOURS - CONSULTANTS AND LEGAL COUNSEL

A separate form is required for each consultant or legal counsel

Board File Number: Enbridge Corporate Cost Allocation Consultation

Party Name: School Energy Coalition

Legal Counsel Name: Jay Shepherd (JS)

Year of Call: 1980

Law Firm: Shibley Righton LLP

Consultant Name:

Years of Relevant Experience (curriculum vitae must be attached):

Consultant Firm:

	Hours	Hourly Rate	Sub-total	GST	Total
Preparation	11.0	$330.00	$3,630.00	N/A	$3,630.00
Attendance - Technical Conference	0.0	$330.00	$0.00	N/A	$0.00
Attendance - Settlement Conference	0.0	$330.00	$0.00	N/A	$0.00
Attendance - Oral Hearing	5.3	$330.00	$1,749.00	N/A	1,749.00
Argument	0.0	$330.00	$0.00	N/A	$0.00
Case Management	0.0	$330.00	$0.00	N/A	$0.00
TOTALS	16.30	$330.00	$5,379.00	N/A	$5,379.00

Note: All claims must be in Canadian dollars. If applicable, state exchange rate__________, and country of initial currency ____________________.

ENBRIDGE CORPORATE COST ALLOCATION CONSULTATION

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
06-OCT-2008	Various emails;	JS	0.1					0.1
07-OCT-2008	Review package; many emails;	JS	0.2					0.2
14-OCT-2008	Review material;	JS	1.1					1.1
14-OCT-2008	Review agenda;	JS	0.1					0.1
16-OCT-2008	Review;	JS	0.5					0.5
17-OCT-2008	Review materials; attend at consult meeting (2.3);	JS	0.7				2.3	3.0
21-OCT-2008	Many emails;	JS	0.7					0.7
27-OCT-2008	Many emails; review responses;	JS	2.7					2.7
11-NOV-2008	Many emails;	JS	0.2					0.2
25-AUG-2009	Many emails;	JS	0.1					0.1
26-AUG-2009	Various emails;	JS	0.1					0.1
01-OCT-2009	Many emails;	JS	0.2					0.2
03-OCT-2009	Review pre-meeting materials	JS	1.0					1.0
05-OCT-2009	Attend at consultative (3.0); prep for meeting; many emails; notes and report;	JS	1.2				3.0	4.2
06-OCT-2009	Various emails;	JS	0.2					0.2
25-OCT-2009	Review material;	JS	0.5					0.5
24-DEC-2009	Various emails, scan reports	JS	0.2					0.2
27-DEC-2009	Review RCAM package	JS	1.2					1.2

2008

2009

SHIBLEY RIGHTON LLP
Barristers and Solicitors

Sandra E. Dawe
Direct Line 416-214-5481
Direct Fax 416-214-5482
sandra.dawe@shibleyrighton.com

TORONTO OFFICE:
250 University Avenue, Suite 700, Toronto, Ontario, M5H 3E5
Main 416 214-5200 Toll free 1-877-214-5200
Facsimile 416 214-5400

WINDSOR OFFICE:
2510 Ouellette Avenue, Suite 301, Windsor, Ontario, N8X 1L4
Main 519 969-9844 Toll free 1-866-422-7988
Facsimile 519 969-8045

www.shibleyrighton.com

Please reply to the TORONTO OFFICE

April 28, 2010

File No. 2040103

Director, Regulatory Affairs
Enbridge Gas Distribution Inc.
500 Consumers Road
North York, ON M2J 1P8

Dear Mr. ~~Ryckman~~: Bonnie Adams

Re: Enbridge DSM Consultative

As you may be aware, Mr. Shepherd is no longer practicing at this firm. Upon reviewing the file we have noticed that there is a outstanding claim for work done in the period from October 2005 to September 2009. Please find enclosed our claim which we trust you will find satisfactory. Please make payment by cheque payable to Shibley Righton LLP In Trust.

Should you have any questions or concerns, please do not hesitate to contact the undersigned.

Yours truly,

SHIBLEY RIGHTON LLP

Sandra E. Dawe
SED/tw
Enclosures 2

Shibley Righton LLP
c/o School Energy Coalition

250 University Avenue, Suite 700
Toronto, Ontario
M5H 3E5

Tel: (416)214-5481
Fax: (416) 214-5482

INVOICE

Date	Description	Amount
03/10/2005 to 30/12/2006	Service with respect to the ***Enbridge DSM Consultative*** as per detailed dockets attached - 21.8 hours @ $210.00	$4,578.00
31/05/2007 to 21/09/2009	Service with respect to the ***Enbridge DSM Consultative*** as per detailed dockets attached - 181.7 hours @ $300.00	$54,510.00
	Subtotal	$59,088.00
	Goods and Services Tax	$2,954.40
	Total (*please make cheque payable to Shibley Righton LLP In Trust*)	$62,042.40

ENBRIDGE DSM CONSULTATIVE

EB-2006-0021 proceeding was held

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
03-OCT-2005	Audit committee telephone meeting;	JS	1.0					1.0
13-OCT-2005	Email to subcommittee members; review draft;	JS	0.5					0.5
14-OCT-2005	Email to subcommittee members;	JS	0.2		2005			0.2
17-OCT-2005	Various emails to subcommittee members;	JS	0.3					0.3
21-OCT-2005	Revise agreement and send;	JS	1.7					1.7
24-OCT-2005	Review and edit terms of reference;	JS	1.1					1.1
26-OCT-2005	Prepare for meeting; audit subcommittee meeting;	JS	1.3					1.3
21-DEC-2005	Email to Richard Lanni; review agreement;	JS	0.2					0.2
03-JAN-2006	Review evidence;	JS	1.8					1.8
06-JAN-2006	Email Richard Lanni; review argument;	JS	0.8					0.8
07-MAR-2006	Email Company;	JS	0.1					0.1
14-SEP-2006	Review terms of reference; various emails;	JS	1.3					1.3
19-SEP-2006	Various emails;	JS	0.2					0.2
04-OCT-2006	Email Rodney;	JS	0.2					0.2
05-OCT-2006	Many emails;	JS	0.7					0.7
10-OCT-2006	Review revised terms of reference;	JS	0.4		2006			0.4
13-OCT-2006	Prep for meeting; audit committee meeting (1.0);	JS	0.4				1.0	1.4
18-OCT-2006	Review meeting materials; Audit Committee meeting (1.1);	JS	0.2				1.1	1.3
01-NOV-2006	Various emails;	JS	0.3					0.3
02-NOV-2006	Various emails;	JS	0.3					0.3
06-NOV-2006	Emails;	JS	0.3					0.3
08-NOV-2006	Many emails; review list;	JS	0.8					0.8
09-NOV-2006	Emails; review materials;	JS	0.8					0.8

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
10-NOV-2006	Conference call and prep;	JS	1.0					1.0
14-NOV-2006	Telephone conference with Susan; review agreement;	JS	0.6		2006			0.6
15-NOV-2006	Telephone conference with Susan; review materials;	JS	0.3					0.3
16-NOV-2006	Various emails;	JS	0.2					0.2
21-NOV-2006	Review plan;	JS	0.3					0.3
29-NOV-2006	Various emails; review report and other issues;	JS	1.6					1.6
30-NOV-2006	Attend at audit committee meeting;	JS					0.8	0.8
31-MAY-2007	Email to Judith Ramasy;	JS	0.1					0.1
01-JUN-2007	Telephone conference with Judith Ramsay; various emails;	JS	0.3		2007			0.3
06-JUN-2007	Telephone conference with Vince de Rosa;	JS	0.3					0.3
07-JUN-2007	Email to Judith Ramasy;	JS	0.1					0.1
13-JUN-2007	Email re meeting;	JS	0.1					0.1
14-JUN-2007	Consultative meeting (2.0); prep;	JS	0.2				2.0	2.2
28-NOV-2007	Various emails regarding audit;	JS	0.3					0.3
05-MAR-2008	Review union material; various emails;	JS	0.5					0.5
06-MAR-2008	Various emails;	JS	0.2					0.2
07-MAR-2008	Many emails;	JS	0.4					0.4
09-MAR-2008	Various emails;	JS	0.2					0.2
10-MAR-2008	Various emails;	JS	0.1					0.1
12-MAR-2008	Various emails;	JS	0.2		2008			0.2
18-MAR-2008	Various emails;	JS	0.1					0.1
19-MAR-2008	Various emails;	JS	0.1					0.1
20-MAR-2008	Many emails; review scoring; telephone conference with Kai Millyard:	JS	1.0					1.0
01-APR-2008	Various emails;	JS	0.2					0.2

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
04-APR-2008	Various emails;	JS	0.2					0.2
09-APR-2008	Many emails;	JS	0.4					0.4
14-APR-2008	Review email exchange; prep for meeting;	JS	0.4					0.4
15-APR-2008	Review additional docs provided;	JS	1.2					1.2
16-APR-2008	Prep for audit meeting; many emails telephone conference with Kai Millyard (several); attend at meeting (1.7);	JS	2.7				1.7	4.4
20-APR-2008	Amend confidentiality agreement; various emails;	JS	0.4					0.4
28-APR-2008	Review revised Grover report; email;	JS	1.1					1.1
02-MAY-2008	Various emails;	JS	0.3					0.3
06-MAY-2008	Various emails;	JS	0.4					0.4
15-MAY-2008	Various emails re confidentiality agmt;	JS	0.2					0.2
21-MAY-2008	Review email from Brophy and attachments; do compare to find changes; responding email;	JS	0.3					0.3
22-MAY-2008	Various emails;	JS	0.2					0.2
24-MAY-2008	Many emails;	JS	0.8					0.8
26-MAY-2008	Many emails;	JS	0.8					0.8
27-MAY-2008	Various emails; analysis of problem with report independence;	JS	1.3					1.3
28-MAY-2008	Review many emails; scan report for issues; many emails with other intervenors;	JS	1.1					1.1
29-MAY-2008	Prep for meeting; attend by telephone at meeting (1.7); many emails and follow up discussion;	JS	1.3				1.7	3.0
30-MAY-2008	Drafting and revising comments on Staff Paper;	JS	11.8					11.8
03-JUN-2008	Review Audit Report and notes; man emails;	JS	1.7					1.7
04-JUN-2008	Attend at audit meeting (2.0); telephone conference with Kai Millyard; many emails; analysis of Kai's points;	JS	2.8				2.0	4.8

2008

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
05-JUN-2008	Various emails; review materials;	JS	1.0					1.0
06-JUN-2008	Many emails;	JS	0.6					0.6
10-JUN-2008	Many emails;	JS	0.3					0.3
11-JUN-2008	Many emails; analysis of conference issue; telephone conference with Kai; Audit committee meeting (1.8);	JS	1.5				1.8	3.3
12-JUN-2008	Many emails; review documents;	JS	1.0					1.0
16-JUN-2008	Many emails; telephone conference with Kai; review background materials;	JS	1.1					1.1
17-JUN-2008	Intervenor conference call; review decision; many emails; draft and revise letter to company; review reports;	JS	3.7			2008		3.7
18-JUN-2008	Telephone conference with Kai; many emails; review docs;	JS	3.8					3.8
19-JUN-2008	Review materials; many emails; meeting with Patrick Hoey;	JS	1.5					1.5
20-JUN-2008	Many emails forward docs;	JS	0.9					0.9
23-JUN-2008	Many emails; review Kai's comments;	JS	0.5					0.5
24-JUN-2008	Many emails; audit committee meeting (0.2); telephone conference with Kai Millyard; review documents; new issues list;	JS	1.6				0.2	1.8
25-JUN-2008	Many emails; review reports; review calcs;	JS	3.3					3.3
26-JUN-2008	Audit meeting(2.0); prep; many emails; telephone conference with Kai Millyard;	JS	2.2				2.0	4.2
27-JUN-2008	Many emails;	JS	1.3					1.3
30-JUN-2008	Various emails;	JS	0.2					0.2
02-JUL-2008	Telephone conference with Kai Millyard; prep for meeting; telephone conference with Vince de Rose; many emails;	JS	1.0					1.0

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
03-JUL-2008	Many emails; review documents from Judith;	JS	1.0					1.0
04-JUL-2008	Many emails;	JS	0.9					0.9
07-JUL-2008	Many emails;	JS	0.8					0.8
08-JUL-2008	Audit meeting (2.0); prep for meeting; many emails telephone conference with Kai Millyard; telephone call with Judith;	JS	4.0				2.0	6.0
09-JUL-2008	Many emails;	JS	0.8					0.8
10-JUL-2008	Many emails; review Kai issues;	JS	0.6					0.6
11-JUL-2008	Many emails;	JS	0.4					0.4
12-JUL-2008	Review background materials; various emails;	JS	1.1					1.1
13-JUL-2008	Various emails; review background materials;	JS	0.3					0.3
14-JUL-2008	Review and annotate Summit Blue Materials;	JS	3.0					3.0
15-JUL-2008	Review auditor memo; many emails; Background material; Kai notes;	JS	1.2					1.2
16-JUL-2008	Many emails;	JS	0.8					0.8
18-JUL-2008	Many email; EAC meeting; review various documents;	JS	3.1					3.1
19-JUL-2008	Many emails; prep for final reports;	JS	1.1					1.1
20-JUL-2008	Many emails;	JS	1.0					1.0
21-JUL-2008	Review materials; EAC meeting; many emails;	JS	2.0					2.0
22-JUL-2008	Review materials; many emails; EAC meeting;	JS	1.8					1.8
23-JUL-2008	Many emails; draft and revise intervenor report; review EGD report;	JS	3.8					3.8
24-JUL-2008	Many email; telephone conference with Kai;	JS	1.2					1.2
25-JUL-2008	Edit report; telephone conference with Kai; many emails; review many revision; telephone conference with Jade;	JS	2.9					2.9
27-JUL-2008	Many emails; review revised summary report;	JS	1.0					1.0

2008

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
28-JUL-2008	Many emails; telephone conference with Kai; telephone conference with Judith;	JS	1.0					1.0
30-JUL-2008	Many emails; review proposed amendments; review potential study;	JS	1.3					1.3
31-JUL-2008	Many emails;	JS	0.3					0.3
01-AUG-2008	Review TMG report; many emails;	JS	1.1					1.1
19-AUG-2008	Many emails;	JS	0.4					0.4
07-SEP-2008	Review package;	JS	0.5					0.5
08-SEP-2008	Various emails; meeting with Kai;	JS	2.0					2.0
11-SEP-2008	Various emails;	JS	0.1					0.1
12-SEP-2008	Many emails;	JS	0.8					0.8
15-SEP-2008	Many emails; review materials;	JS	1.2					1.2
17-SEP-2008	Many emails; review Dunsky input;	JS	0.7					0.7
18-SEP-2008	Prep for meeting;	JS	1.2					1.2
19-SEP-2008	Prep for meeting, EAC meeting (1.3); many emails; telephone conference with Kai Millyard;	JS	3.3				1.3	4.6
25-SEP-2008	Review material from Judith;	JS	1.6					1.6
09-OCT-2008	Various emails; review various document;	JS	0.7					0.7
10-OCT-2008	Review schedule;	JS	0.2					0.2
15-OCT-2008	Various emails;	JS	0.1					0.1
16-OCT-2008	Various emails;	JS	0.1					0.2
20-OCT-2008	Meeting with Fiona Glasford;	JS	2.0					2.0
21-OCT-2008	Many emails;	JS	0.3					0.3
24-OCT-2008	Many emails;	JS	0.7					0.7
31-OCT-2008	Prep	JS	1.0					1.0
31-OCT-2008	Prep for meeting;	JS	1.0					1.0
01-NOV-2008	Review many report and studies;	JS	3.2					3.2
02-NOV-2008	Review studies;	JS	1.5					1.5

2008

DATE	DESCRIPTION	LYR.	PREP.	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
03-NOV-2008	Many emails; prep for meeting;	JS	0.8					0.8
04-NOV-2008	Conference call meeting (0.7); prep for meeting; telephone conference with Millyard;	JS	2.6				0.7	3.3
06-NOV-2008	Telephone conference with Vince de Rose;	JS	0.3					0.3
07-NOV-2008	Various emails; review CME IRs;	JS	0.3					0.3
10-NOV-2008	Many emails; review new materials;	JS	1.6					1.6
14-NOV-2008	Many emails;	JS	0.2					0.2
17-NOV-2008	Many emails; review paper	JS	1.0					1.0
18-NOV-2008	Prep for meeting; many emails;	JS	1.2					1.2
19-NOV-2008	Many emails;	JS	0.4		2008			0.4
21-NOV-2008	Many emails;	JS	0.2					0.2
24-NOV-2008	Joint EAC meeting; prep; many emails;	JS	2.7					2.7
25-NOV-2008	Attend at consultative (6.6) net; many emails;	JS	0.9				6.6	7.5
26-NOV-2008	Many emails; review EGD data;	JS	0.7					0.7
28-NOV-2008	Review slides;	JS	0.7					0.7
06-DEC-2008	Many emails;	JS	0.2					0.2
11-DEC-2008	Various emails;	JS	0.2					0.2
17-DEC-2008	Review revised Terms of Reference;	JS	0.2					0.2
19-DEC-2008	Review Terms of Reference; many emails;	JS	0.4					0.4
21-DEC-2008	Review and edit terms of reference; many emails;	JS	1.7					1.7
22-DEC-2008	Various emails;	JS	0.2					0.2
05-JAN-2009	Review email and attachments;	JS	0.2					0.2
06-JAN-2009	Various emails;	JS	0.2					0.2
08-JAN-2009	Various emails;	JS	0.1		2009			0.1
12-JAN-2009	Many emails;	JS	0.2					0.2
14-JAN-2009	Joint EAC Committee; prep for meeting; various emails;	JS	2.6					2.6
19-JAN-2009	Various emails; review meeting notes;	JS	0.3					0.3

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
20-JAN-2009	Review audit proposals; various emails;	JS	0.8					0.8
22-JAN-2009	Many emails;	JS	0.2					0.2
23-JAN-2009	Many emails;	JS	0.3					0.3
06-FEB-2009	Many emails;	JS	0.4					0.4
07-FEB-2009	Review revised Cadmus proposal;	JS	0.3					0.3
08-FEB-2009	Review letter and report; send email for clarification;	JS	1.0					1.0
09-FEB-2009	Many emails;	JS	0.3					0.3
10-FEB-2009	Many emails;	JS	0.3					0.3
11-FEB-2009	Many emails;	JS	0.1					0.1
23-FEB-2009	Many emails;	JS	0.1					0.1
25-FEB-2009	Meeting with auditors; prep;	JS	1.8					1.8
02-MAR-2009	Email to Cadmus;	JS	0.2					0.2
13-MAR-2009	Review submissions;	JS	1.5					1.5
24-MAR-2009	Many emails;	JS	0.3					0.3
26-MAR-2009	Various emails;	JS	0.2					0.2
30-MAR-2009	Review materials;	JS	0.3					0.3
01-APR-2009	Various emails;	JS	0.1					0.1
15-APR-2009	Various emails;	JS	0.1					0.1
16-APR-2009	Many emails;	JS	0.2					0.2
17-APR-2009	Many emails;	JS	0.4					0.4
18-APR-2009	Many emails;	JS	0.2					0.2
27-APR-2009	Many emails;	JS	0.3					0.3
30-APR-2009	Review update of work plan; review Corinne's report;	JS	0.3					0.3
05-MAY-2009	Attend at Audit Comm (1.5);	JS	0.0				1.5	1.5
12-MAY-2009	Many emails; review comments from Chris;	JS	0.2					0.2
14-MAY-2009	Review Neme comments;	JS	0.2					0.2

2009

DATE	DESCRIPTION	LYR	PREP	TECHNICAL	ARGUMENT	SETTLEMENT	ORAL	TIME
21-MAY-2009	Various emails;	JS	0.1					0.1
25-MAY-2009	Many emails;	JS	0.1					0.1
11-JUN-2009	Many emails;	JS	0.2					0.2
12-JUN-2009	Many emails; review EGD responses;	JS	0.3					0.3
17-JUN-2009	Many emails;	JS	0.1					0.1
23-JUN-2009	Various emails;	JS	0.1					0.1
02-JUL-2009	Review Casmus draft;	JS	0.5					0.5
19-JUL-2009	Review audit summary report;	JS	0.5					0.5
11-AUG-2009	Various emails;	JS	0.1					0.1
20-AUG-2009	Various emails;	JS	0.1					0.1
26-AUG-2009	Various emails;	JS	0.1					0.1
31-AUG-2009	Review audit report;	JS	1.0					1.0
02-SEP-2009	Attend at consultative (3.0); draft letter many emails;	JS	1.7				3.0	4.7
03-SEP-2009	Letter to EGD; many emails;	JS	1.1					1.1
03-SEP-2009	Many emails;	JS	0.3					0.3
07-SEP-2009	Various emails;	JS	0.1					0.1
21-SEP-2009	Review EGD letter;	JS	0.1					0.1

2009

Jay Shepherd
Professional Corporation
120 Eglinton Avenue East
Suite 500
Toronto, Ontario M4P 1E2

BY EMAIL

May 24, 2010

Aird & Berlis LLP
Barristers and Solicitors
181 Bay Street
18th Floor, Box 754
Toronto, Ontario
M5J 2T9

Attn: Dennis O'Leary

Dear Dennis:

Re: Shibley Righton Cost Claims

Further to your letter of May 18th, as discussed I have reviewed the dockets and supporting materials for the two claims referred to, and I have the following comments.

Corporate Cost Allocations

This claim is for preparing for and attending RCAM consultative meetings called by Enbridge in 2008 and 2009. The total is 5.3 hours of meeting attendance, and 11.00 hours of reviewing materials provided by Enbridge and discussing them with other intervenors. I did not find any errors in this claim.

I note that the dockets include the full 16.3 hours, but in two separate columns, with a "Total" column on the right hand side. This matches the claim itself.

(416) 804-2767
jay.shepherd@canadianenergylawyers.com
www.canadianenergylawyers.com

Jay Shepherd Professional Corporation

DSM

This claim covers my involvement in the Enbridge DSM consultative for part of 2005, all of 2006, 2007, 2008, and most of 2009. For three of those years, I was a member of the Audit Committee (later called the EAC), and in one year in particular the time involved on that committee was quite substantial. This all seems as expected, so the overall quantum does not seem grossly out of whack given the time period involved.

I did a detailed line by line review of the dockets, including review of backup documents and cross-referencing to my datebook and my email archive. In that review, I found some that are not correct, as follows:

Date	Description	Hours	Problem
21-Oct-05	Revise agreement and send	1.7	This relates to the DSM Co-ordinator Agreement, and should not have been billed
21-Dec-05	Email to Richard Lanni, Review agreement	0.2	same
6-Jan-06	Email Richard Lanni, Review argument (should be "agreement")	0.8	same
14-Nov-06	Telephone conference with Susan, Review agreement	0.6	same
15-Nov-06	Telephone conference with Susan, Review materials	0.3	same
28-May-08	Drafting and revising comments on Staff Paper	11.8	This relates to the SEC submissions in the Board's consultation on Rate Design, EB-2007-0031, and was included through a posting error
18-Jul-08	Many emails, EAC meeting, Review various documents	3.1	In the breakdown, 2.6 out of the 3.1 hours should be in the column relating to attendance rather than prep. However, the docket is otherwise correct.
1-Aug-08	Review TMG Report, Many emails	1.1	The TMG report related to CIS, not DSM. However, it was not at this time. This docket should have referred to the Marbek report, which was provided to the EAC members at this time. With that change, the docket is correct.
20-Oct-08	Meeting with Fiona Glasford	2.0	This related to Union's DSM consultative, not Enbridge, and was included in error.
7-Nov-08	Various emails, Review CME IRs,	0.3	This relates to the clearance of Enbridge deferral accounts, EB-2008-0271, and was included here in error.
14-Jan-09	Joint EAC Committee, Prep for meeting, Various emails	2.6	In the breakdown, 2.0 out of the 2.6 hours should be in the column relating to attendance rather than prep. However, the docket is otherwise correct.

Jay Shepherd Professional Corporation

In total, 17.7 hours appear to have been docketed to this file incorrectly, and should be removed. All are either items that should have been treated as unbillable, or related to other matters that have since been the subject of completed cost awards.

I should add that I looked at all of the other dockets, and found them to be fine. In particular, I draw your attention to June 17, 2008, which refers to a review of a "decision". This was an EAC matter, and the "decision" referred to was the Generic DSM decision. After a discussion between the intervenor EAC members, I needed to review that decision in order to be sure of the wording before writing a letter to Enbridge, which I then did.

Based on my analysis, I believe that the 21.8 hours claimed at $210/hr should be reduced to 18.2 hours, and the 181.7 hours at $300 should be reduced to 167.6 hours.

However, I also note that the hourly rates appear to be wrong. Until the end of 2007, the hourly rate for cost claims relevant to my time was $210.00 per hour, and then it changed to $330.00 per hour. The number of hours at the lower rate should be the 18.2 hours just noted, plus 3.4 hours for 2007 erroneously included at the higher rate, for a total of 21.6 hours. This leaves not 167.6 hours at the higher rate, but 164.2 hours.

By my calculations, the correct amount of the claim is as follows:

21.6 hours at $210.00	$ 4,536.00
164.2 hours at $330.00	$54,186.00
Total Fees	$58,722.00
GST @5%	$ 2,936.10
Full Total	$61,658.10

I have spoken to Shibley Righton about these errors, and they advise that they will provide you with a revised claim this week.

Intervenor Objections

I will contact the other intervenors that I know might be interested in this on an informal basis to see if anyone has a problem with the DSM claim. (I assume there is no concern about the smaller RCAM claim.) While I am confident no-one will object, I am not sure I will get a timely response from all, since there are a lot of things going on and this issue will not be top of mind for anyone.

Jay Shepherd Professional Corporation

I have also spoken to Sandra Dawe, Managing Partner at Shibley Righton. As you and I discussed on the telephone, they are in fact prepared to agree that if because of the late filing of this claim Enbridge ultimately is not allowed to recover some part of this payment from ratepayers through the normal variance account, SR will refund that amount to you at that time. Please speak with Sandra directly to get her confirmation of this.

Conclusion

I hope this is of assistance, Dennis. Please feel free to call me if I can help further. If it would be useful for me to talk directly with Andrew Mandyam or anyone else at your client's office, please let me know and I'll be happy to do so.

Yours very truly,
JAY SHEPHERD P. C.

Jay Shepherd

cc: Sandra Dawe, SR (email)
Wayne McNally, SEC (email)

CME INTERROGATORY #11

INTERROGATORY

Clearance of 2009 Deferral and Variance Account Balances

Reference: Exhibit C, Tab 2, Schedule 2

Please revise this schedule to show the clearances that would likely ensue if forecasted balances to July 1, 2010, were to be included in the amounts to be cleared to ratepayers.

RESPONSE

Exhibit C, Tab 2, Schedule 2 reflects the final principal balance for each deferral and variance account (except the PGVA) with corresponding interest to October 1, 2010. The principal balance for each deferral and variance account is not affected by the clearance date so that whether accounts are cleared on July 1, 2010 or October 1, 2010, the final principal balance remains unchanged. Interest amounts on the final principal balance would change only slightly to reflect the three-month difference in clearance date.

Please refer to the response to BOMA Interrogatory #3 at Exhibit I, Tab 2, Schedule 3 which updates the PGVA balance.

Witnesses: J. Collier
A. Kacicnik
M. Suarez-Sharma

VECC INTERROGATORY #1

INTERROGATORY

Reference: Exhibit A, Tab 2, Schedule 1, Appendix A, Page 1 lines 8 and 9

a) Provide details of the calculation of the amounts and balances in the 2009/2010 OBSDA and OBAVA.
b) Relate the balances to be disposed of to the EB-2009-0043 Settlement Agreement.

RESPONSE

a & b) In the EB-2009-0043 Decision/Settlement Agreement the Board approved the clearance of the balances in the 2008 Open Bill Service D/A of $309,370 and 2008 Open Bill Access V/A of $476,667, plus accrued interest, details of which were provided in evidence. The balances were approved to be cleared over a three year period, 2010 to 2012, and to be shared equally between the Company and ratepayers. The balances in the 2008 accounts were transferred to corresponding 2009 accounts as per the Accounting Order in the same proceeding. The incremental amount in the 2009 Open Bill Service D/A, to achieve the February 2010 balance of $526,150, relates to TMG, OBA stakeholder, and start-up legal charges. The exact magnitude of these amounts was not known during the EB-2009-0043 proceeding, but they were contemplated and referred to in the approved Settlement Agreement, and agreed to be shared equally between the Company and ratepayers once known. In this proceeding, the Company is requesting clearance of the 2010 ratepayer share of these accounts (i.e., 1/3 of its 50% share of the balances).

Witness: K. Culbert

VECC INTERROGATORY #2

INTERROGATORY

Reference: Exhibit B Tab 1 Schedule 3 Page 2 Exhibit B Tab 3 Schedule 5 Page 1

Preamble: "The other revenue change of $6.6 million is due to increased late payment penalty revenue of $5.9 million, an increase in service charges of $1.4 million and a decrease in other revenue of $(0.7) million. This results in a positive impact on earnings".

a) Reconcile the quoted numbers with Ex B, T3, S5 line 1.3 that shows an increase in LPPs from 12.0-14.0 million.
b) Provide statistics on LPPs for 2007-2009 include # LPPs and average amounts.
c) Provide calculation of Impact of increased LPPs on 2009 Revenue and Earnings.

RESPONSE

a) The quoted numbers in the preamble relate to the figures on Exhibit B, Tab 1, Schedule 3, page 1, which show the difference between 2009 Actual Normalized versus 2007 Board Approved. However, Exhibit B, Tab 3, Schedule 5, page 1 relates to 2009 versus 2008 Actual. The variances as stated are accurate in relation to quoted time periods and are not reconcilable to one another.

b) As indicated in response to VECC Interrogatory #2 at Exhibit I, Tab 5, Schedule 2[1] within last years EB-2009-0055 deferral and variance account request for clearance approval application, EGD does not track numbers of LPP transactions and therefore the average amounts requested cannot be calculated.

c) Attempting to isolate and measure a specific change in LPP revenue solely as an impact within earnings is not a meaningful exercise. First, a change in LPP revenue would have to be measured against a specific amount being recovered in rates and additionally would also need to take account of identifiable and related changes in bad debt expense, allowance for doubtful accounts and security deposits relative to assumptions of what levels of these items are being recovered in rates. The incentive regulation model within which EGD's revenues are derived

[1] EB-2009-0055, Exhibit I, Tab 5, Schedule 2 at page 2, (ir).

Witnesses: K. Culbert
R. Lei

and approved has effectively decoupled annual revenues relative to costs and or offsetting or credit revenue streams such as LPP. As indicated in last year's EB-2009-0055 evidence, and in Exhibit B, Tab 3, Schedule 1, page 3 in this year's evidence, the LPP revenue for 2008 actual was \$12.0M and for 2009 actual was \$14.0M.

VECC INTERROGATORY #3

INTERROGATORY

Reference: Exhibit B Tab 2 Schedule 1 Page 1 line 8

Preamble: the cited reference shows at line 8 "Customer security deposits 2009 (53.3) 2008 (44.8) Change (8.5)"

a) Provide statistics regarding residential class SD from 2007-2009 including #, amounts and averages.
b) Provide calculation of impact on 2009 revenue and earnings.
c) Provide calculation of interest on SD that adds to 1.0 million as an O&M expense.

RESPONSE

a) EGD has not tracked numbers of rate class security deposits for the period requested and therefore the average amounts requested cannot be calculated.

b) Please see response to part c) of VECC Interrogatory #2 at Exhibit I, Tab 4, Schedule 2, which applies to this question as well.

c) Please see the table on the next page.

Witnesses: K. Culbert
R. Lei

	Security Deposits ($Millions)	Interest Rate	Interest on Security Deposits ($Millions)
January 2009	46.3	4.12%	0.2
February 2009	48.6	4.12%	0.2
March 2009	50.9	2.45%	0.1
April 2009	51.9	2.45%	0.1
May 2009	54.4	2.45%	0.1
June 2009	55.0	2.45%	0.1
July 2009	59.4	0.55%	
August 2009	61.0	0.55%	
September 2009	52.5	0.55%	0.2
October 2009	54.3	0.55%	
November 2009	53.5	0.55%	
December 2009	57.0	0.55%	
			1.0

Witnesses: K. Culbert
R. Lei

VECC INTERROGATORY #4

INTERROGATORY

Reference: Exhibit B, Tab 4 Schedule 1Page 5 line 2 adjustments: Exhibit B Tab 4 Schedule 2, Page 3

a) Provide amounts for RCAM and CAM for 2007-2009
b) Provide an explanation of the major drivers of the change(s) in the difference between RCAM and CAM 2007-2009

RESPONSE

a)

	2009	**2008**	**2007**
CAM	$34.3M	$32.2M	$27.7M
RCAM	$21.2M	$19.1M	$18.1M
Difference	**$13.1M**	**$13.1M**	**$ 9.6M**

b) CAM and RCAM are derived using different allocation models.

CAM reflects the departmental cost allocations from Enbridge Inc. to EGD. The increase in CAM during the period 2007 to 2009 primarily arises from the increase in the overall departmental cost base over this time horizon.

RCAM on the other hand reflects service-based fully allocated costs in alignment with the methodology accepted by the OEB. The increase in RCAM over the same time period primarily results from higher direct charges, including higher stock based compensation.

Given the varied basis of derivation of CAM and RCAM, the differences do not lend themselves to a direct comparison.

Witness: L. Liauw

VECC INTERROGATORY #5

INTERROGATORY

Reference: Exhibit D Tab 1 Schedule 1 Page 22

a) Provide a breakdown and explanation of the increase of $2.1 million in Stock Based Compensation. Include both the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan, and number(s) of participants and average payments.
b) Compare to 2007 and 2008 including relevant explanations regarding stock/strike price changes.
c) Confirm the 2009 RCAM amount and relationship to the increase in SBC.

RESPONSE

a) Please see the response to SEC Interrogatory #7 at Exhibit I, Tab 5, Schedule 7, part e.

b)

	2009	2008	2007
Stock strike price	$39.61	$40.42	$38.26

The strike price is determined based on the fair market value, as noted below.

The 2007 strike price of the stock option grant was based on the last board lot sale price of common shares of the Corporation on The Toronto Stock Exchange on the last Trading Day immediately prior to the grant date.

The strike price of the 2008 and 2009 stock option grants were based on the weighted average of the board lot trading prices per share on the Toronto Stock Exchange, or the New York Stock Exchange, for the last five Trading Days immediately prior to the day of the grant.

Witnesses: N. Kishinchandani
L. Liauw

c)

	2009	2008	Increase
RCAM	$21.2M	$19.1M	$2.1M
SBC	$4.3M	$3.1M	$1.2M

Witnesses: N. Kishinchandani
L. Liauw

VECC INTERROGATORY #6

INTERROGATORY

Reference: Exhibit C, Tab 1, Schedule 5, Appendix A, Page 5 of 6 Table 4

a) Provide an explanation for the apparent decline in # customer meters in the latter part of 2009.
b) Compare the apparent change to 2008.
c) What is the impact on the average use calculation of declining customer meters in 2009.
d) How does this affect the budget for 2010?

RESPONSE

a) A variance versus a forecast of monthly customer meters is usually attributable to factors such as, fluctuations in monthly customer additions, timing lag in activating a new customer meter or account, an increase or decrease in monthly 'lock' meters and the timing lag associated with in activating new or existing lock meters.

A lock meter or customer is defined as customer whose gas meter is locked and no gas is flowing. These customers or premises can be vacant (e.g. new construction, move-in/move-out, bankruptcies, etc.), customers may be switching from gas to an alternate energy source, for payment or credit reasons, or due to seasonal usage (e.g. cottage).

Figures 1 and 2 illustrate a degree of volatility in the monthly profile of residential lock meters and customer additions.[1] Previously, the Company has discussed the lag time that occurs between when the service line and meter are installed (which underpins the capital expenditure and customer additions) and when customer moves into the premise and calls to have meter unlocked (which activates the customer's account and underpins the meter). Please refer to EB-2008-0219, Exhibit B, Tab 1, Schedule 5, Appendix B, page 4 for a more detailed explanation of this lag.

[1] Residential customer meters account for 92% of total customer meter additions - other rate classes are impacted by other volatility factors, such as rate migration. For simplicity, the response here is focused on the residential sector.

The 2009 actual monthly profile is shown in Figures 1 and 2.

As shown in Figure 2, customer additions were in decline after April and August, and then increasing in September and October. As a result of the fluctuations in customer additions, timing lag and an increase in lock meters, representing a combination of timing and economic factors. The decline in customer meters is consistent with the expected reduction in customer additions most recently discussed in evidence at EB-2009-0172, Exhibit B, Tab 1, Schedule 4. At that time, it was shown that economic conditions in Ontario had deteriorated since the latter half of 2007, throughout 2008 and into 2009. The impact of this deteriorating economic condition is also reflected in a sharp annual reduction in residential housing starts between 2008 and 2009 in Table 1.

The Ontario Minister of Finance was quoted to state last September that the global economy, since the fall of 2008, has entered into a crisis that was not experienced for some 80 years.[2] Interestingly, the increase in capital additions in September and October of 2009, allowing for a lag for the activation of the customer account, will be reflected in a slight increase in the customer additions realized in the early part of the 2010 actual data.

TABLE 1 - RESIDENTIAL HOUSING STARTS

	2003	2004	2005	2006	2007	2008	2009
EGD Franchise	56,482	54,189	49,724	46,350	43,847	50,832	32,695

Source (extracted from): Canada Mortgage and Housing Corporation (CMHC) data.

[2] "Public Accounts of Ontario 2008-2009 Annual Report and Consolidated Financial Statements." Ministry of Finance. September 25, 2009. <http://www.fin.gov.on.ca/english/budget/paccts/2009/09_ar.html>

Figure 1: Historical Actual Residential Lock Customers

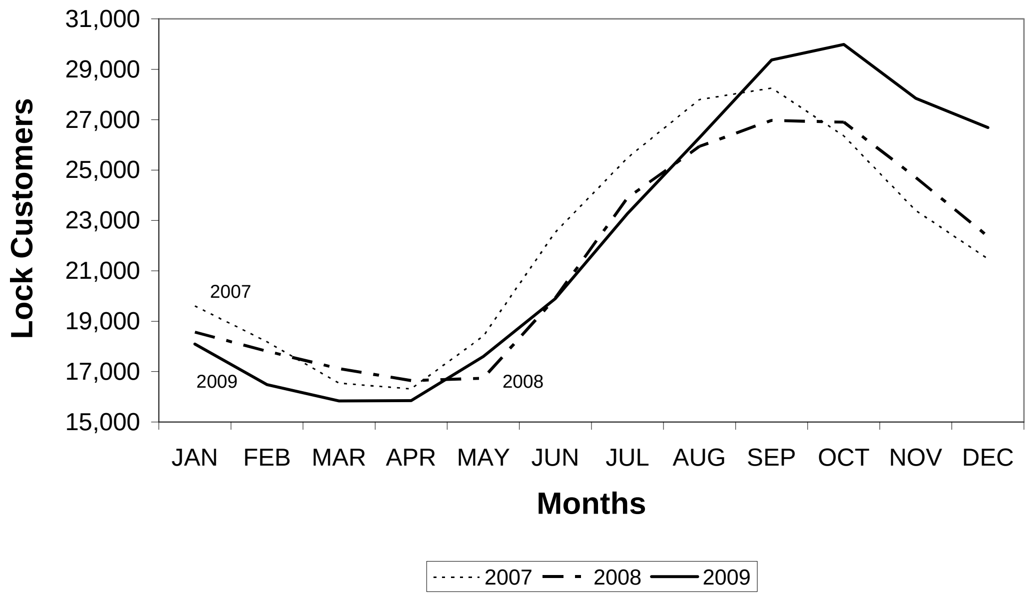
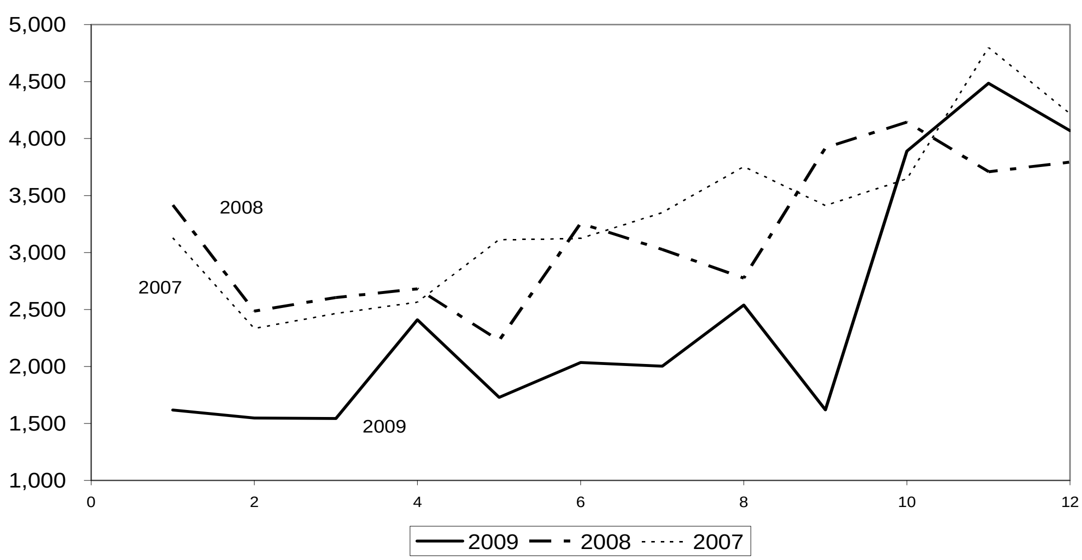


Figure 2: Historical Actual Residential Customer Additions



b) Table 2 below compares the residential customer meters between 2009 and 2008. Please see the response to part (a) for the explanation.

TABLE 2
GENERAL SERVICE RATE 1
2009 AND 2008 ACTUAL CUSTOMERS

		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	Exhibit Reference
Item .		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	
1.1	2009 Customer Meters	1,732,249	1,735,493	1,737,672	1,739,610	1,739,878	1,739,355	1,737,856	1,737,104	1,727,462	1,715,474	1,714,182	1,729,905	1,732,187	EB-2010-0042 Exhibit B Tab 3 Schedule 4 Page 1 Col. 1 Item 1.1
1.2	2008 Customer Meters	1,696,273	1,700,261	1,703,379	1,705,962	1,707,943	1,707,091	1,706,577	1,707,023	1,709,269	1,713,355	1,719,442	1,725,664	1,708,520	EB-2009-0172 Exhibit B Tab 1 Schedule 5 Appendix A Page 15 Col. 1 Item 1.1

c) Average use per customer is calculated by dividing the volume by aggregate unlock meter count on a monthly basis.[3] That means, total average use per customer is a nonlinear function of customer count as well as a linear function of both customer count and each customer's usage.

Since the majority of the reduction in customer meters was driven by new construction housing starts, the lower the new construction customer meters added to the system, the higher the aggregate average use per customer, all else being equal.

The reason for this is that average use for new homes are typically lower than the existing homes as a consequence of the ongoing changes to the Building Code[4], higher energy efficient space heating equipment and water heating, better windows and housing envelop improvements amongst other things.

For example, if we were to ignore the impact of higher energy efficient furnaces in a new home and focus on the impact of the new Building Code on usage with all other factors held constant, the average use for new homes will be approximately 2,054 m^3, or 21.5%[5] lower than the current reported aggregate weather normalized residential average use per customer of 2,616[6] m^3, which is a composite of both new and old homes.

[3] Please refer to Tables 4-5 at Exhibit C, Tab 1, Schedule 5, Appendix A.
[4] Please refer to EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Page 10.
[5] Please refer to EB-2009-0172, Exhibit B, Tab 1, Schedule 5, Page 12.
[6] Exhibit C, Tab 1, Schedule 5, Appendix A, Table 1, Col. 2.

If we were to assume further that:

- there is no lag time between customer additions and customer meters,
- the current experienced reduction in residential new construction (i.e. excluding replacement) customers of 7,190 between 2009 and 2008 actual are added back to the proforma Average Use True Up Variance Account (AUTUVA) calculation, and
- 2009 actual new construction customer additions were equal to 2008,

the proforma residential average use impact will be as follows:

$$\text{Proforma Annual Average Use } (m^3) = \frac{1{,}732{,}187*2{,}616 + 7{,}190*2{,}054}{1{,}732{,}187 + 7{,}190}$$

Proforma Annual Average Use (m^3) = 2,614, < AUTUVA average use of 2,616 m^3

Consequently, the proforma impact of increasing current reported 2009 customer meters of 1,732,187 by 7,190 is a further 2 m^3 (=2,614 m^3-2,616 m^3) reduction in average use. As a result, the proforma impact on the AUTUVA amount will be an additional of $0.25 million debited to rate payers in accordance with the AUTUVA calculation at Exhibit C, Tab 1, Schedule 5, Appendix A, Table 1.

d) As 2010 Budget was already approved by the Board and was developed based upon the latest available information during the budget development process back in Spring 2009, there is no impact on the Budget for 2010.

VECC INTERROGATORY #7

INTERROGATORY

References: Exhibit C Tab 2 Schedule 2 Page 2 of 6; Exhibit A, Tab 2, Schedule 1, Appendix A, Page 1

a) For non-PGVA accounts (lines 2-19) indicate the Year(s) for which the balances were accumulated
b) Provide a version that shows the 2009 opening and closing balances, interest and total for each account.

RESPONSE

a) In reference to Exhibit C, Tab 2, Schedule 2, page 2, which details the amounts being requested for clearance, all lines relate to 2009 approved deferral and variance accounts and represent balances accumulated during 2009, with the following noted exceptions:

- Lines 6, 7, and 8, the 2008 DSMVA, LRAM, and SSMVA, represent balances related to 2008 DSM activities. The 2008 DSMVA principal amount was recorded in 2008 as it was a variance against budgeted spending. The 2008 LRAM and SSMVA amounts were recorded in 2009 once the Board approved the amounts for clearance, following the annual DSM audit and settlement negotiations with the DSM consultative.

- Line 9 represents the 2010 installment of the approved CASDA recovery. CASDA costs incurred between 2005 and 2007 were approved for recovery over five years, 2008 through 12, in EB-2007-0731.

- Line 11 represents the 2010 revenue requirement that results from amounts recorded in the 2007, 2008, and 2009 GDARCDA accounts.

- Line 14 represents the 2010 revenue requirement that results from amounts recorded in the 2008 and 2009 MPFDA accounts.

- Line 15 represents the requested recovery of the 2010 ratepayer share of the 2009 OBSDA balance. As approved in the EB-2009-0043 proceeding, the 2008 OBSDA balance (transferred to the 2009 account), plus incremental costs incurred in 2009, would be shared equally between the company and ratepayers and be cleared over a three year period beginning in 2010.

- Line 16 represents the requested recovery of the 2010 ratepayer share of the 2009 OBAVA balance. As approved in the EB-2009-0043 proceeding, the 2008 OBAVA balance (transferred to the 2009 account) would be shared equally between the company and ratepayers and be cleared over a three year period beginning in 2010.

b) The table on the following page provides the requested account balance information. As noted in the response to part a), in some instances the account balances are not the amounts currently requested for clearance.

ENBRIDGE GAS DISTRIBUTION INC. DEFERRAL & VARIANCE ACCOUNT ACTUAL BALANCES

Line No.	Account Description	Account Acronym	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
			Actual at January 1, 2009			Actual at December 31, 2009			Actual at February 28, 2010		
			Principal	Interest	Total	Principal	Interest	Total	Principal[3]	Interest	Total
			($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)
	Non Commodity Related Accounts										
1.	Demand Side Management V/A	2008 DSMVA	(73.3)	(55.2)	(128.5)	(73.3)	(56.0)	(129.3)	(73.3)	(56.1)	(129.4)
2.	Lost Revenue Adjustment Mechanism	2008 LRAM	-	-	-	37.3	-	37.3	37.3	0.1	37.4
3.	Shared Savings Mechanism V/A	2008 SSMVA	-	-	-	5,800.0	5.3	5,805.3	5,803.2	5.3	5,808.5
4.	Class Action Suit D/A	2009/10 CASDA	-	-	-	18,838.2	1,517.1	20,355.3	18,838.2	1,534.4	20,372.6 [1]
5.	Deferred Rebate Account	2009 DRA	-	-	-	2.7	(0.1)	2.6	2.7	(0.1)	2.6
6.	Gas Distribution Access Rule Costs D/A	2009 GDARCDA	-	-	-	188.7	0.6	189.3	188.7	0.8	189.5
7.	Ontario Hearing Costs V/A	2009 OHCVA	-	-	-	533.9	0.1	534.0	531.7	0.6	532.3
8.	Open Bill Service D/A	2009/10 OBSDA	-	-	-	539.4	15.4	554.8	526.2	15.9	542.1 [1]
9.	Open Bill Access V/A	2009/10 OBAVA	-	-	-	476.7	5.4	482.1	476.7	5.9	482.6 [1]
10.	Municipal Permit Fees D/A	2009 MPFDA	-	-	-	916.1	-	916.1	916.1	-	916.1
11.	Average Use True-Up V/A	2009 AUTUVA	-	-	-	5,626.9	-	5,626.9	5,626.9	5.2	5,632.1
12.	Tax Rate and Rule Change V/A	2009 TRRCVA	-	-	-	(350.0)	-	(350.0)	(350.0)	(0.3)	(350.3)
13.	Earnings Sharing Mechanism D/A	2009 ESMDA	-	-	-	(18,750.0)	-	(18,750.0)	(18,750.0)	(17.2)	(18,767.2)
14.	IFRS Transition Costs D/A	2009 IFRSTCDA	-	-	-	2,060.3	-	2,060.3	2,111.0	1.9	2,112.9
15.	Ex-Franchise Third Party Billing Services D/A	2009 EFTPBSDA	-	-	-	(27.9)	-	(27.9)	(27.9)	-	(27.9)
16.	Total non commodity related accounts		(73.3)	(55.2)	(128.5)	15,819.0	1,487.8	17,306.8	15,857.5	1,496.4	17,353.9
	Commodity Related Accounts										
17.	Purchased Gas V/A	2009 PGVA	-	-	-	(246,927.0)	(2,069.2)	(248,996.2)	(116,672.9)	(2,287.8)	(118,960.7) [2]
18.	Transactional Services D/A	2009 TSDA	-	-	-	(7,062.1)	(3.1)	(7,065.2)	(7,062.1)	(9.5)	(7,071.6)
19.	Unaccounted for Gas V/A	2009 UAFVA	-	-	-	9,596.7	-	9,596.7	9,596.7	8.8	9,605.5
20.	Storage and Transportation D/A	2009 S&TDA	-	-	-	(1,591.3)	(3.1)	(1,594.4)	(1,594.8)	(4.6)	(1,599.4)
21.	Total commodity related accounts		-	-	-	(245,983.7)	(2,075.4)	(248,059.1)	(115,733.1)	(2,293.1)	(118,026.2)
22.	Total Deferral and Variance Accounts		(73.3)	(55.2)	(128.5)	(230,164.7)	(587.6)	(230,752.3)	(99,875.6)	(796.7)	(100,672.3)

Notes:
1. The December 31, 2008 balances in the 2008 CASDA, 2008 OBSDA, and 2008 OBAVA were rolled forward into the corresponding 2009 accounts during 2009 as per Board Orders.
2. The 2009 PGVA balance includes the roll forward of the 2008 PGVA forecasted December 31, 2008 balance as approved in the EB-2008-0348 proceeding.
3. February 28, 2010 principal balances which differ from December 31, 2009 balances are due to the true-up of year end accruals, and in the 2009 PGVA as a result of the Board approved rider in place through March 31, 2010.

VECC INTERROGATORY #8

INTERROGATORY

Reference: EB-2009-0172 Exhibit I Tab 7 Schedule 17 Page 1

Preamble: “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.”

a) What is EGDs Plan for review of the details of the transactions and revenue related to the 2009 TSDA?

RESPONSE

As indicated in the responses to the interrogatories and proceeding noted above, the Company indicated it would file an application requesting the review and approval of the 2009 TSDA and other variance accounts, presumably by March 2010. This EB-2010-0042 proceeding is that application. It is through this review process where interrogatories are to be asked about the balances being requested for clearance. As an example, Board Staff has asked, within its Interrogatory # 5, for the composition of the TS and TSDA amounts.

Witnesses: K. Culbert
A. Kacicnik
D. Small

VECC INTERROGATORY #9

INTERROGATORY

Reference: Exhibit C, Tab 1, Schedule 5 Page 4 of 4 plus Appendix

Preamble: Tables 4 and 5 of Appendix A illustrate the corresponding actual weather normalized volumes and actual customers for both Rate 1 and Rate 6 that underpin Table 1's calculation. Further rate class detail and explanations are provided at Exhibit B, Tab 3, Schedule 2.

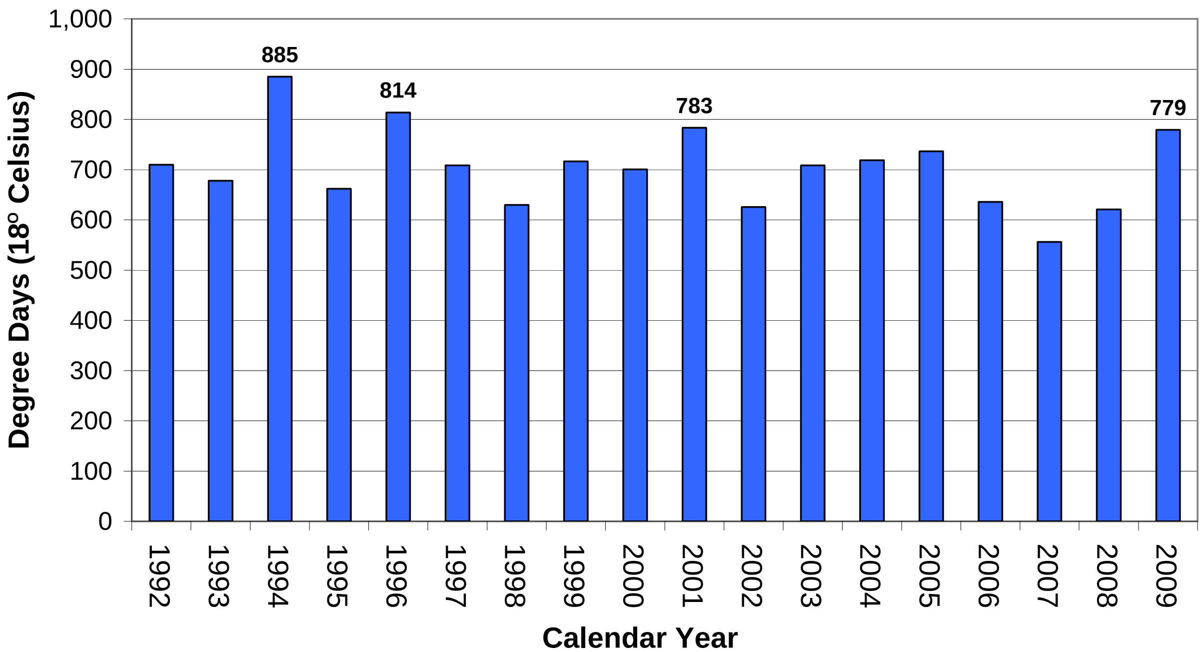
a) Provide details of the 2009 Weather.
b) Provide the calculation of normalized volumes for Residential Rate 1 and Rate 6.
c) Compare to Budget/forecast.
d) Reconcile to 2009 Rate 1 AUTVA calculation.

RESPONSE

a) The 2009 Budget volumes reflect the meter reading heating degree days forecast for the Central Region of 3,514.[1] The 2009 actual meter reading heating degree days for the Central Region were 3,764, 250 degree days higher than budget. Meter reading heating degree days are acquired by amalgamating Gas Supply heating degree days with the billing schedules. The majority of the increase in degree days was attributable to colder than normal weather during the major heating months. In particular, January 2009 was the fourth coldest month of January since 1992 as shown in Figure 1. The 2009 actual meter reading heating degree days for both Eastern and Niagara Regions were 4,472 and 3,527, respectively. They were higher than their corresponding budget degree days of 4,363 and 3,435, respectively.

[1] Please refer to EB-2008-0219, Exhibit B, Tab 1, Schedule 5, page 2.

Figure 1: Historical Month of January Actual Meter Reading Degree Days



b) The General Service normalization[2] is conducted on customers at a group level, i.e., by six regions of the Company's franchise area, by thirteen revenue classes and by three gas service types. Then, these customer grouping numbers are aggregated and consolidated into the reported Rate 1 and Rate 6 normalized volumes. Therefore, it would be difficult to display 234 calculations (i.e., 234 =13 revenue classes x 3 gas service types x 6 regions). As a result, in order to demonstrate the calculation for as many customers (i.e., magnitude), as clearly and as simple as possible, Tables 1 and 2 illustrate a proforma calculation for revenue classes 20 and 48 within the Central Weather Zone by consolidating four Greater Toronto Area regions which account for 87% and 62% of the total 2009 actual Rate 1 and Rate 6 normalized volumes, respectively. Table 3 provides a description of the revenue class grouping. Tables 4 and 5 present a reconciliation of the normalized volumes between the customer grouping levels and rate classes.

[2] Please refer to the 2009 Gas Volume Budget Evidence at EB-2008-0219, Exhibit B, Tab 1, Schedule 5, pages 33-36 for the detailed description of the normalization methodology.

TABLE 1 - NORMALIZATION VOLUMES CALCULATION FOR CENTRAL ZONE, REVENUE CLASS 20, AND SALES

	Col. 1	Col. 2	Col. 3 = Col. 1*1000000/Col. 2	Col. 4	Col. 5 = Col. 3 * Col. 2/1000000	Col. 6 = Col. 3 - Col. 4	Col. 7	Col. 8	Col. 9 = Col. 6/Col. 7 * Col. 8	Col. 10 = Col. 9 *Col. 2/1000000	Col. 11 = Col. 10 + Col. 5
	Actual Volumes (10^6m^3)	Unlocks	Total Actual Use per Unlocks (m^3)	Actual Baseload Use Per Customer (m^3)	Baseload Volumes (10^6m^3)	Actual Heatload Use Per Customer (m^3)	Actual Balanced Point Degree Days	Budget Balanced Point Degree Days	Normalized Heatload Use per Customer (m^3)	Normalized Heatload Volumes (10^6m^3)	Total Normalized Volumes (10^6m^3)
Jan	405.4	733,831	552	156	115	396	674	545	320	235	349.8
Feb	361.3	736,453	491	139	102	351	619	548	311	229	331.8
Mar	297.7	739,737	402	129	95	274	478	451	259	191	286.5
Apr	207.8	742,919	280	99	74	181	297	278	169	125	199.2
May	99.6	746,051	133	93	69	40	104	124	48	36	105.3
Jun	67.3	750,050	90	87	65	3	30	10	1	1	65.7
Jul	51.5	755,436	68	68	52	0	0	0	0	0	51.5
Aug	51.3	760,899	67	67	51	0	0	0	0	0	51.3
Sep	50.1	761,240	66	66	50	0	6	0	0	0	50.1
Oct	112.0	761,708	147	73	55	74	138	64	35	26	81.7
Nov	157.6	766,391	206	94	72	111	206	215	116	89	161.1
Dec	264.3	782,322	338	102	80	236	370	401	256	200	279.8
Total	2,125.9	753,086			73		2,922	2,636		1,133	2,013.8
Exhibit Reference											Reconciled to Table 4 Aggregate Sum of Item No. 1.19+1.22 +1.25+1.28

TABLE 2 - NORMALIZATION VOLUMES CALCULATION FOR CENTRAL ZONE, REVENUE CLASS 48, AND SALES

	Col. 1	Col. 2	Col. 3 = Col. 1*1000000/Col. 2	Col. 4	Col. 5 = Col. 3 * Col. 2/1000000	Col. 6 = Col. 3 - Col. 4	Col. 7	Col. 8	Col. 9 = Col. 6/Col. 7 * Col. 8	Col. 10 = Col. 9 *Col. 2/1000000	Col. 11 = Col. 10 + Col. 5
	Actual Volumes (10^6m^3)	Unlocks	Total Actual Use per Unlocks (m^3)	Actual Baseload Use Per Customer (m^3)	Baseload Volumes (10^6m^3)	Actual Heatload Use Per Customer (m^3)	Actual Balanced Point Degree Days	Budget Balanced Point Degree Days	Normalized Heatload Use per Customer (m^3)	Normalized Heatload Volumes (10^6m^3)	Total Normalized Volumes (10^6m^3)
Jan	228.8	77,389	2,956	1,915	148	1,042	674	545	842	65	213.3
Feb	204.6	77,876	2,627	1,808	141	820	619	548	726	57	197.3
Mar	168.0	78,262	2,146	1,565	122	581	478	451	549	43	165.4
Apr	109.2	78,366	1,394	1,189	93	205	297	278	191	15	108.2
May	51.9	78,183	664	565	44	99	104	124	118	9	53.4
Jun	31.9	78,123	409	409	32	0	30	10	0	0	31.9
Jul	28.6	77,625	369	369	29	0	0	0	0	0	28.6
Aug	23.9	77,143	310	310	24	0	0	0	0	0	23.9
Sep	24.6	75,751	325	325	25	0	6	0	0	0	24.6
Oct	53.0	75,251	704	585	44	119	138	64	55	4	48.2
Nov	92.4	76,030	1,215	1,011	77	204	206	215	213	16	93.0
Dec	166.9	78,633	2,122	1,141	90	981	370	401	1,064	84	173.3
Total	1,183.9	77,386			72		2,922	2,636		293	1,161.4 Reconciled to Table 5 Aggregate Sum of Items 2.19+2.22 +2.25+2.28

TABLE 4 - RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 1

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes ($10^6 m^3$)	Customer Meters
1.1	10	Metro	Sales	42.2	22,840
1.2	10	Metro	Ontario Transportation	2.2	1,138
1.3	10	Metro	Western Transportation	12.0	5,295
1.4	10	Western	Sales	27.6	10,903
1.5	10	Western	Ontario Transportation	1.6	820
1.6	10	Western	Western Transportation	9.7	3,961
1.7	10	Central	Sales	29.9	14,699
1.8	10	Central	Ontario Transportation	1.7	1,159
1.9	10	Central	Western Transportation	9.9	5,218
1.10	10	Northern	Sales	62.1	23,704
1.11	10	Northern	Ontario Transportation	3.0	1,668
1.12	10	Northern	Western Transportation	17.9	7,835
1.13	10	Eastern	Sales	47.3	20,818
1.14	10	Eastern	Ontario Transportation	2.5	1,654
1.15	10	Eastern	Western Transportation	12.5	5,562
1.16	10	Niagara	Sales	11.2	5,773
1.17	10	Niagara	Ontario Transportation	0.7	470
1.18	10	Niagara	Western Transportation	3.8	1,818
1.19	20	Metro	Sales	777.7	265,670
1.20	20	Metro	Ontario Transportation	76.9	32,318
1.21	20	Metro	Western Transportation	344.2	112,643
1.22	20	Western	Sales	428.0	168,283
1.23	20	Western	Ontario Transportation	43.2	20,502
1.24	20	Western	Western Transportation	222.9	82,498
1.25	20	Central	Sales	232.1	99,771
1.26	20	Central	Ontario Transportation	22.9	12,154
1.27	20	Central	Western Transportation	115.3	46,163
1.28	20	Northern	Sales	576.1	219,362
1.29	20	Northern	Ontario Transportation	46.9	21,537
1.30	20	Northern	Western Transportation	241.2	85,639
1.31	20	Eastern	Sales	364.8	154,600
1.32	20	Eastern	Ontario Transportation	30.3	16,172
1.33	20	Eastern	Western Transportation	138.3	54,540
1.34	20	Niagara	Sales	182.4	81,001
1.35	20	Niagara	Ontario Transportation	18.7	10,423
1.36	20	Niagara	Western Transportation	89.3	36,790
1.37	50	Metro	Sales	57.4	10,387
1.38	50	Metro	Ontario Transportation	3.9	1,047
1.39	50	Metro	Western Transportation	17.9	3,582
1.40	50	Western	Sales	33.7	7,597
1.41	50	Western	Ontario Transportation	2.3	750
1.42	50	Western	Western Transportation	11.8	2,716
1.43	50	Central	Sales	18.5	4,851
1.44	50	Central	Ontario Transportation	1.8	656
1.45	50	Central	Western Transportation	8.9	2,266
1.46	50	Northern	Sales	52.2	10,399
1.47	50	Northern	Ontario Transportation	3.5	972
1.48	50	Northern	Western Transportation	18.2	3,614
1.49	50	Eastern	Sales	19.6	4,563
1.50	50	Eastern	Ontario Transportation	1.2	408
1.51	50	Eastern	Western Transportation	5.8	1,318
1.52	50	Niagara	Sales	8.7	2,306
1.53	50	Niagara	Ontario Transportation	0.7	258
1.54	50	Niagara	Western Transportation	3.2	850
1.55	60	Metro	Sales	0.7	2,584
1.56	60	Metro	Ontario Transportation	0.0	162
1.57	60	Metro	Western Transportation	0.2	763
1.58	60	Western	Sales	0.1	91
1.59	60	Western	Ontario Transportation	0.0	1
1.60	60	Western	Western Transportation	0.0	13
1.61	60	Central	Sales	0.2	146
1.62	60	Central	Ontario Transportation	0.0	3
1.63	60	Central	Western Transportation	0.0	29
1.64	60	Northern	Sales	0.3	231

TABLE 4 - RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 1

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes ($10^6 m^3$)	Customer Meters
1.65	60	Northern	Ontario Transportation	0.0	6
1.66	60	Northern	Western Transportation	0.1	42
1.67	60	Eastern	Sales	0.3	312
1.68	60	Eastern	Ontario Transportation	0.0	4
1.69	60	Eastern	Western Transportation	0.0	26
1.70	60	Niagara	Sales	0.1	278
1.71	60	Niagara	Ontario Transportation	0.0	12
1.72	60	Niagara	Western Transportation	0.0	51
1.73	61	Metro	Sales	4.2	4,483
1.74	61	Metro	Ontario Transportation	0.3	343
1.75	61	Metro	Western Transportation	1.5	1,389
1.76	61	Western	Sales	0.8	787
1.77	61	Western	Ontario Transportation	0.1	116
1.78	61	Western	Western Transportation	0.4	453
1.79	61	Central	Sales	0.9	823
1.80	61	Central	Ontario Transportation	0.1	94
1.81	61	Central	Western Transportation	0.4	360
1.82	61	Northern	Sales	1.0	896
1.83	61	Northern	Ontario Transportation	0.1	104
1.84	61	Northern	Western Transportation	0.5	356
1.85	61	Eastern	Sales	1.4	1,349
1.86	61	Eastern	Ontario Transportation	0.1	145
1.87	61	Eastern	Western Transportation	0.5	459
1.88	61	Niagara	Sales	0.7	986
1.89	61	Niagara	Ontario Transportation	0.0	72
1.90	61	Niagara	Western Transportation	0.2	277
1	Total Rate 1 Normalized Volumes			4,533.8	1,732,187
				reconciled to Exhibit C, Tab 1, Schedule 5, Appendix A, Page 5, Col. 13, Item 1.1	reconciled to Exhibit C, Tab 1, Schedule 5, Appendix A, Page 5, Col. 13, Item 1.2

*Note: Please refer to Table 3 for definition.

TABLE 5 -RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 6

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes (10^6m^3)	Customer Meters
2.1	12	Metro	Sales	157.0	1,465
2.2	12	Metro	Ontario Transportation	22.6	239
2.3	12	Metro	Western Transportation	437.7	1,864
2.4	12	Western	Sales	23.7	174
2.5	12	Western	Ontario Transportation	2.0	23
2.6	12	Western	Western Transportation	62.3	256
2.7	12	Central	Sales	6.4	106
2.8	12	Central	Ontario Transportation	0.4	8
2.9	12	Central	Western Transportation	11.7	80
2.10	12	Northern	Sales	15.0	176
2.11	12	Northern	Ontario Transportation	0.9	17
2.12	12	Northern	Western Transportation	23.4	129
2.13	12	Eastern	Sales	32.9	644
2.14	12	Eastern	Ontario Transportation	2.7	50
2.15	12	Eastern	Western Transportation	57.2	490
2.16	12	Niagara	Sales	8.5	298
2.17	12	Niagara	Ontario Transportation	0.6	22
2.18	12	Niagara	Western Transportation	7.3	122
2.19	48	Metro	Sales	528.4	26,829
2.20	48	Metro	Ontario Transportation	177.6	3,384
2.21	48	Metro	Western Transportation	311.8	9,427
2.22	48	Western	Sales	274.9	18,700
2.23	48	Western	Ontario Transportation	65.0	1,661
2.24	48	Western	Western Transportation	154.4	5,339
2.25	48	Central	Sales	94.9	8,356
2.26	48	Central	Ontario Transportation	18.2	684
2.27	48	Central	Western Transportation	58.8	2,395
2.28	48	Northern	Sales	263.2	23,501
2.29	48	Northern	Ontario Transportation	35.8	1,743
2.30	48	Northern	Western Transportation	145.8	6,545
2.31	48	Eastern	Sales	191.0	13,001
2.32	48	Eastern	Ontario Transportation	29.8	1,069
2.33	48	Eastern	Western Transportation	141.6	4,023
2.34	48	Niagara	Sales	95.7	7,604
2.35	48	Niagara	Ontario Transportation	40.4	744
2.36	48	Niagara	Western Transportation	52.0	2,033
2.37	73	Metro	Sales	86.1	2,295
2.38	73	Metro	Ontario Transportation	28.9	290
2.39	73	Metro	Western Transportation	60.7	942
2.40	73	Western	Sales	45.5	712
2.41	73	Western	Ontario Transportation	61.4	130
2.42	73	Western	Western Transportation	38.1	321
2.43	73	Central	Sales	10.8	161
2.44	73	Central	Ontario Transportation	35.0	39
2.45	73	Central	Western Transportation	6.7	60
2.46	73	Northern	Sales	29.5	395
2.47	73	Northern	Ontario Transportation	25.1	75
2.48	73	Northern	Western Transportation	36.1	202
2.49	73	Eastern	Sales	11.5	98
2.50	73	Eastern	Ontario Transportation	13.8	26
2.51	73	Eastern	Western Transportation	11.2	48
2.52	73	Niagara	Sales	17.2	157
2.53	73	Niagara	Ontario Transportation	12.5	43
2.54	73	Niagara	Western Transportation	14.4	81
2.55	79	Metro	Sales	18.8	1,714
2.56	79	Metro	Ontario Transportation	4.0	239
2.57	79	Metro	Western Transportation	10.8	701
2.58	79	Western	Sales	3.6	216
2.59	79	Western	Ontario Transportation	1.4	29
2.60	79	Western	Western Transportation	2.2	84
2.61	79	Central	Sales	1.9	206
2.62	79	Central	Ontario Transportation	1.3	26
2.63	79	Central	Western Transportation	0.9	53
2.64	79	Northern	Sales	2.8	254

TABLE 5 -RECONCILIATION BETWEEN CUSTOMER GROUPING LEVEL AND RATE CLASS VOLUMES AND METERS - RATE 6

Item No.	Revenue Class*	Region	Gas Service Type	Normalized Volumes (10^6m^3)	Customer Meters
2.65	79	Northern	Ontario Transportation	0.8	24
2.66	79	Northern	Western Transportation	1.1	72
2.67	79	Eastern	Sales	5.5	480
2.68	79	Eastern	Ontario Transportation	1.6	57
2.69	79	Eastern	Western Transportation	2.5	166
2.70	79	Niagara	Sales	1.1	168
2.71	79	Niagara	Ontario Transportation	0.6	26
2.72	79	Niagara	Western Transportation	0.6	56
2.73	83	Metro	Sales	1.9	39
2.74	83	Metro	Ontario Transportation	0.7	7
2.75	83	Metro	Western Transportation	1.1	14
2.76	83	Western	Sales	0.1	3
2.77	83	Western	Ontario Transportation	0.1	1
2.78	83	Western	Western Transportation	0.6	4
2.79	83	Central	Sales	0.2	2
2.80	83	Central	Ontario Transportation	0.1	1
2.81	83	Central	Western Transportation	0.5	3
2.82	83	Northern	Sales	0.1	4
2.83	83	Northern	Ontario Transportation	0.2	2
2.84	83	Northern	Western Transportation	0.3	1
2.85	83	Eastern	Sales	0.0	1
2.86	83	Eastern	Ontario Transportation	0.2	2
2.87	83	Eastern	Western Transportation	0.2	1
2.88	83	Niagara	Sales	0.1	2
2.89	83	Niagara	Ontario Transportation	0.1	1
2.90	86	Metro	Sales	1.6	46
2.91	86	Metro	Ontario Transportation	89.9	280
2.92	86	Metro	Western Transportation	7.6	53
2.93	86	Western	Sales	0.2	12
2.94	86	Western	Ontario Transportation	10.4	38
2.95	86	Western	Western Transportation	2.1	17
2.96	86	Central	Sales	0.4	37
2.97	86	Central	Ontario Transportation	0.8	7
2.98	86	Central	Western Transportation	0.3	9
2.99	86	Northern	Sales	0.2	17
2.100	86	Northern	Ontario Transportation	3.0	18
2.101	86	Northern	Western Transportation	1.3	22
2.102	86	Eastern	Sales	1.1	45
2.103	86	Eastern	Ontario Transportation	6.4	23
2.104	86	Eastern	Western Transportation	1.5	18
2.105	86	Niagara	Sales	0.1	15
2.106	86	Niagara	Ontario Transportation	0.5	2
2.107	86	Niagara	Western Transportation	0.1	5
2.108	90	Metro	Sales	0.9	41
2.109	90	Metro	Ontario Transportation	0.4	9
2.110	90	Metro	Western Transportation	1.4	27
2.111	90	Western	Sales	0.2	5
2.112	90	Western	Ontario Transportation	0.0	1
2.113	90	Western	Western Transportation	0.1	3
2.114	90	Central	Sales	0.1	3
2.115	90	Central	Ontario Transportation	0.1	1
2.116	90	Central	Western Transportation	0.7	3
2.117	90	Northern	Sales	0.9	11
2.118	90	Northern	Ontario Transportation	0.2	2
2.119	90	Northern	Western Transportation	0.5	4
2.120	90	Eastern	Sales	0.5	4
2.121	90	Eastern	Ontario Transportation	0.1	1
2.122	90	Eastern	Western Transportation	0.6	2
2.123	90	Niagara	Sales	0.2	12
2.124	90	Niagara	Ontario Transportation	0.0	2
2.125	90	Niagara	Western Transportation	0.3	6
2	Total Rate 6 Normalized Volumes			4,298.6	154,736
				reconciled to	reconciled to
				Exhibit C, Tab 1, Schedule 5, Appendix A, Page 6, Col. 13, Item 1.1	Exhibit C, Tab 1, Schedule 5, Appendix A, Page 6, Col. 13, Item 1.2

*Note: Please refer to Table 3 for definition.

TABLE 3 - REVENUE CLASS DESCRIPTION

Revenue Class Group	Revenue Class Description	Rate Class
10	Residential Space Heating And Other Uses	1
12	Apartment Space Heating And Other Uses	6
20	Residential Space Heating, Water Heating And Other Uses	1
48	Commercial Space Heating, Water Heating And Other Uses	6
50	Residential Space Heating, Water Heatnig, Pool Heating, And Other Uses	1
60	Residential Non Heating And Other Uses	1
61	Residential Water Heating And Other Uses	1
73	Industrial Space Heating, Water Heating And Other Uses	6
79	Commerical Non Heating And Other Uses	6
83	Industrial Non Heating And Other Uses	6
86	Apartment Non Heating, Water Heating, Pool Heating, And Other Uses	6
90	Commerical Space Heating, Pool Heating, Water Heating, And Other Uses	6
97	Natural Gas Vehicle Retail Stations	9

c) Exhibit B, Tab 3, Schedule 2, pages 2 and 3 provide the comparison between weather normalized volumes for Rate 1 and Rate 6 and 2009 Board Approved Volume Budget along with commentary.

d) Total Rate 1 and Rate 6 normalized volumes and customer meters reported on Tables 4 and 5 in section (b) above are reconciled to Items 1.1 and 1.2 from Tables 4 and 5 of Exhibit C, Tab 1, Schedule 5, Appendix A, pages 5 and 6. Item 1.3 from Tables 4 and 5 of Exhibit C, Tab 1, Schedule 5, Appendix A, pages 5 and 6 are then reconciled to the Column 2 of the AUTUVA calculation at Exhibit C, Tab 1, Schedule 5, Appendix A, Table 1.

VECC INTERROGATORY #10

INTERROGATORY

References: Exhibit A Tab 2 Schedule 1 Appendix A; Exhibit C Tab 2 Schedule 1Page 2 para 5

a) Provide a summary report of the activities and costs incurred related to the 2009 International Financial Reporting Standards Transition Costs Deferral Account (IFRSTCDA).

RESPONSE

Please see chart below for a breakdown of the amounts in the IFRS Transition D/A:

Summary of IFRSTCDA charges

Service Provider	Activities	Amount ('000's)
Enbridge Inc.	Project Leadership, People Readiness, Process Changes, System Change reviews, Technical Accounting, expenses	956
Deloitte	Project Management	482
Incremental Internal Labour	Accounting policies analysis and preparation	261
Ernst & Young	Overhead Capitalization Study	214
PWC	Review of Draft policies	161
Gannett Fleming	Depreciation consultation	15
Other Services	Misc.	22
Total		2,111

Witnesses: K. Culbert
J. Jozsa

SEC INTERROGATORY #1

INTERROGATORY

[Ex. A/2/1/ App. A] Please provide a detailed breakdown of the entries in each of the following accounts:

a. Ontario Hearing Costs V/A
b. IFRS Transition Costs D/A

RESPONSE

a) Please see the response to CME Interrogatory #10 at Exhibit I, Tab 3, Schedule 10.

b) Please see the response to VECC Interrogatory #10 at Exhibit I, Tab 4, Schedule 10.

Witnesses: K. Culbert
J. Jozsa

SEC INTERROGATORY #2

INTERROGATORY

[Ex. B/1/2] Please restate this table on a non-normalized basis.

RESPONSE

The requested table has been restated on an unnormalized basis on page 2 of this interrogatory.

Witness: K. Culbert

SUMMARY
RETURN ON EQUITY & EARNINGS SHARING DETERMINATION
ENBRIDGE GAS DISTRIBUTION

ONTARIO UTILITY
FOR THE YEAR ENDED DECEMBER 31, 2009

	Col. 1	Col. 2	Col. 3
Line No.	Description	Reference	Actual Unnormalized ($millions) & (%'s)
1.	**Part A) Return on Rate Base & Revenue (Deficiency) / Sufficiency**		
2.	Gas Sales		2,306.7
3.	Transportation Revenue		644.0
4.	Less Cost of Gas		1,938.6
5.	Gas Distribution Margin		1,012.1
6.	Transmission, Compr. and Storage Revenue		1.6
7.	Other Revenue		40.9
8.	Other Income		7.5
9.	Total - TC&S, Oth. Rev. & Inc.		50.0
10.	Operations, Maintenance & Administration		336.9
11.	Depreciation & amortization		251.0
12.	Fixed financing costs		6.5
13.	Debt redemption premium amortization		0.3
14.	Company share of IR agreement tax savings		9.6
15.	Municipal & capital taxes		44.4
16.	Total O&M, Depr., & other		648.7
17.	Utility Income before Income Tax	(line 5 + line 9 - line 16)	413.4
18.	Less: Income Taxes		87.1
19.	**Utility Income**		**326.3**
20.	Gross plant		5,500.5
21.	Accumulated depreciation		(2,089.5)
22.	Net plant		3,411.0
23.	Working capital		405.0
24.	**Utility Rate Base**		**3,816.0**
25.	Indicated Return on Rate Base %	(line 19 / line 24)	8.551%
26.	Less: Required Rate of Return %		7.450%
27.	(Deficiency) / Sufficiency %		1.101%
28.	Net Earnings (Deficiency) / Sufficiency	(line 27 x line 24)	42.01
29.	Provision for Income Taxes		20.69
30.	Gross Earnings (Deficiency) / Sufficiency	(line 28 divide by 67.0%)	62.71
31.	**50% Earnings sharing to ratepayers**	(line 30 x 50%)	**N/A**
32.	**Part B) Return on Equity & Revenue (Deficiency) / Sufficiency**		
33.	Utility Income before Income Tax		413.4
34.	Less: Long Term Debt Costs		150.4
35.	Less: Short Term Debt Costs		2.7
36.	Less: Cost of Preferred Capital		3.4
37.	Net Income before Income Taxes		256.9
38.	Less: Income Taxes		87.1
39.	Net Income Applicable to Common Equity	(line 37 - line 38)	169.8
40.	Common Equity		1,373.8
41.	Approved ROE %	(EB-2007-0615 for Earnings Sharing 8.31% + 100 bp)	9.31%
42.	Achieved Rate of Return on Equity %	(line 39 divide by line 40)	12.36%
43.	Resulting (Deficiency) / Sufficiency in Return on Equity %		3.05%
44.	Net Earnings (Deficiency) / Sufficiency	(line40 x line 43)	41.90
45.	Provision for Income Taxes		20.64
46.	Gross Earnings (Deficiency) / Sufficiency	(line 44 divide by 67.0%)	62.54
47.	**50% Earnings sharing to ratepayers**	(line 46 x 50%)	**N/A**

Note: The variance in the gross earnings sufficiency calculated in Part A and Part B is due to rounding.

SEC INTERROGATORY #3

INTERROGATORY

[Ex. B/3/5] Please provide further details on the increase in Miscellaneous Other Revenues from $1.4 million in 2007 to $7.5 million in 2009.

RESPONSE

High Performance New Construction Program - Ontario Power Authority (HPNCP-OPA) revenue, a new revenue initiative started in 2008, accounts for $5.9 million of the increase in Miscellaneous other revenues in 2009. This has an offsetting cost of $4.0 million in O&M.

Witness: R. Lei

SEC INTERROGATORY #4

INTERROGATORY

[Ex. B/4/2, p. 1] With respect to this table:

a. Please confirm that, excluding customer care costs (lines 3 and 4), which were subject of a smoothing agreement, the costs on line 17 increased $33.9 million, from $230.8 million in 2007 to $264.7 million in 2009, an increase of 14.7% over two years.

b. Please provide a detailed explanation of the material factors causing the $30.0 million (84.1%) increase in Non-Departmental Expenses and Corporate Cost Allocations (lines 15 and 16) from 2007 to 2009.

c. Please provide details of the $6.5 million (37.2%) increase in capitalized costs from 2007 to 2009, including a copy of any change in capitalization policy that has happened in that period.

RESPONSE

a. Line 17 of Column 4 represents the Board approved 2007 Utility O&M, which includes all regulatory adjustments, whereas Line 17 of Column 1 and 2 are before any regulatory adjustments for corporate cost allocations and CIS fees. Therefore, $321.6 million in 2007 should be compared to $336.6 million in 2009 ($354.6 million on Line 17 less $18.0 million on Line 25). This is an increase of $15.0 million, or 4.7% over two years.

b. Non-Departmental Expenses and the primary drivers of the variances are as follows:

   i. An increase in the Executive & Administration amounts due to realignment of positions and responsibilities.

   ii. Higher STIP amounts reflecting the Company's performance in 2009 as well as the impact of annual merit increase.

   iii. Amounts associated with the alignment of operating practices with the Company's strategy under IR.

Witness: R. Lei

Corporate Cost Allocations:

Corporate cost allocations shown in the table at Exhibit B, Tab 4, Schedule 2, Page 1 incorporate the RCAM utility costs under Column 4 as apposed to the CAM costs which have been reflected under Column 1 and 2. Effectively, an adjustment needs to be made before drawing a comparison between the 2007 and 2009 values.

	2009	2008	2007	2-Yr Increase
CAM	$34.3M	$32.2M	$27.7M	$6.6M
RCAM	$21.2M	$19.1M	$18.1M	$3.1M

CAM has increased $6.6 million over two years largely due to higher stock based compensation (SBC) for EGD employees, higher IT support costs, and higher insurance premiums.

c. The increase in capitalized costs from 2007 to 2009 mainly resulted from the inflation, annual merit increase, pension and benefits, STIP, SBC, and IT support costs.

There has been no change in capitalization policy during this time.

Witness: R. Lei

SEC INTERROGATORY #5

INTERROGATORY

[Ex. C/1/4, p. 2] Please confirm that no part of the CIS purchase qualified for Class 52, and that all of that cost was included as a new addition in 2009 in Class 12.

RESPONSE

EGD confirms that none of the CIS spend amount qualified for inclusion into Capital Cost Allowance, “CCA”, Class 52. Exhibit B, Tab 4, Schedule 1, page 8 shows all qualifying costs which were included into CCA Class 12 in 2009 and the associated CCA treatment (the new CIS costs are found in the second entry for CCA Clas 12 on these charts).

Witness: K. Culbert

SEC INTERROGATORY #6

INTERROGATORY

[Ex. C/1/5, p. 3] Please calculate the increase, if any, in the Rate 6 normalized average use per customer in 2009 resulting from migration from contract rate classes, which customers would tend to have higher average use per customer than other Rate 6 customers. Please show how the calculation was derived, including the difference between normalized and non-normalized results.

RESPONSE

The volume budget and weather normalization for General Service rate classes are conducted at a customer grouping level rather than on an individual customer account basis. As a result, it is not possible to calculate a specific increase on the aggregate 2009 weather normalized actual average use per customer resulting from migration from contract rate classes, or further, which particular customer would tend to have a higher average use per customer than any other Rate 6 customer(s) unless all of the information (i.e. actual, weather normalized and budget) are available on an individual account basis. Note: there are approximately 155,000 Rate 6 customers which would make individual account analysis costly and impractical.

In addition, normalized average use per customer is calculated by dividing the normalized volumes by the aggregate unlock meter count on a monthly basis.[1] That means, total average use per customer is a nonlinear function of customer count as well as a linear function of both customer count and each customer's usage. Therefore, any increase or decrease in one customer's usage in comparison to the rest of the customers will not translate into a one-for-one impact on the overall average use number, all else being equal.

It is possible to calculate the weather normalized volumetric impact of customer migration from contract rate classes to Rate 6 between 2009 actual and 2008 actual by customer trade group, holding other variables constant. Table 1 on the next page illustrates the impact of 901 customers that were migrated from contract rate classes to Rate 6 between 2009 actual and 2008 actual. It is important to note that it is Table 2 of Exhibit C, Tab 1, Schedule 5, Appendix A that is relevant in explaining the Average Use True Up Variance Account (AUTUVA) amount, since the purpose of AUTUVA is to calculate the volumetric variance of aggregate average use per customer for total

[1] Please refer to Tables 4-5 at Exhibit C, Tab 1, Schedule 5, Appendix A.

154,736[2] Rate 6 customers between current year weather normalized actual and the Board Approved budget numbers.

On the other hand, Table 1 on the following page is relevant in explaining the historical weather normalized actual Rate 6 average use graph shown in each Test Year's Gas Volume Budget evidence. This average use graph is reproduced on page 4 as Figure 1. The 2009 weather normalized actual Rate 6 average use per customer of 27,654 m^3 reported in Figure 1 was reconciled to the audited actual Average Use True Up Variance Accounted (AUTUVA) calculation reported in Table 1 of Exhibit C, Tab 1, Schedule 5, Appendix A. Please refer to EB-2008-0219, Exhibit B, Tab 1, Schedule 5, pages 11-18 for further explanation on why the rate migration trend between Rate 6 and contract market rate classes has increased dramatically since the Fall 2006 and why this trend can be volatile and unpredictable.

Table 2 on the following page provides the un-normalized actual volumetric impact of customer migration from contract rate classes to Rate 6 between 2009 actual and 2008 actual by customer trade group.

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[2] Please refer to Table 4 of Exhibit C, Tab 1, Schedule 5, Appendix A.

**TABLE 1 - CUSTOMER MIGRATION FROM CONTRACT RATE CLASSES TO RATE 6
BETWEEN 2009 ACTUAL AND 2008 ACTUAL**

1. Customers migrated to Rate 6 due to rate design changes

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	9	All Other Industrial	5.9
	468	Apartment	180.5
	1	Asphalt	1.8
	35	Business & Financial Service Industries	21.5
	13	Chemical and Chemical Products	8.8
	1	Construction Industries	0.3
	45	Education Services	18.4
	4	Electronics/High Tech	2.7
	30	Food, Beverage, Drug & Tobacco	14.7
	29	Government Services	19.6
	7	Greenhouses/Agriculture	4.2
	25	Health, Social & Other Services	15.1
	20	Hotels	13.1
	6	Non-Metallic Mineral Products	2.4
	4	Other Utility Industries (Cogen)	6.6
	11	Plastic Products	3.8
	48	Primary Metal & Machinery	28.8
	26	Pulp & Paper	52.2
	12	Recreational & Household Industries	8.5
	4	Rubber Products	2.4
	5	Textile Products	2.1
	19	Transportation and Storage and Utilities	19.6
	43	Transportation Equipment	107.4
	21	Wholesale & Retail Trade	14.1
	5	Wood & Furniture Industries	3.0
Total	891		557.2

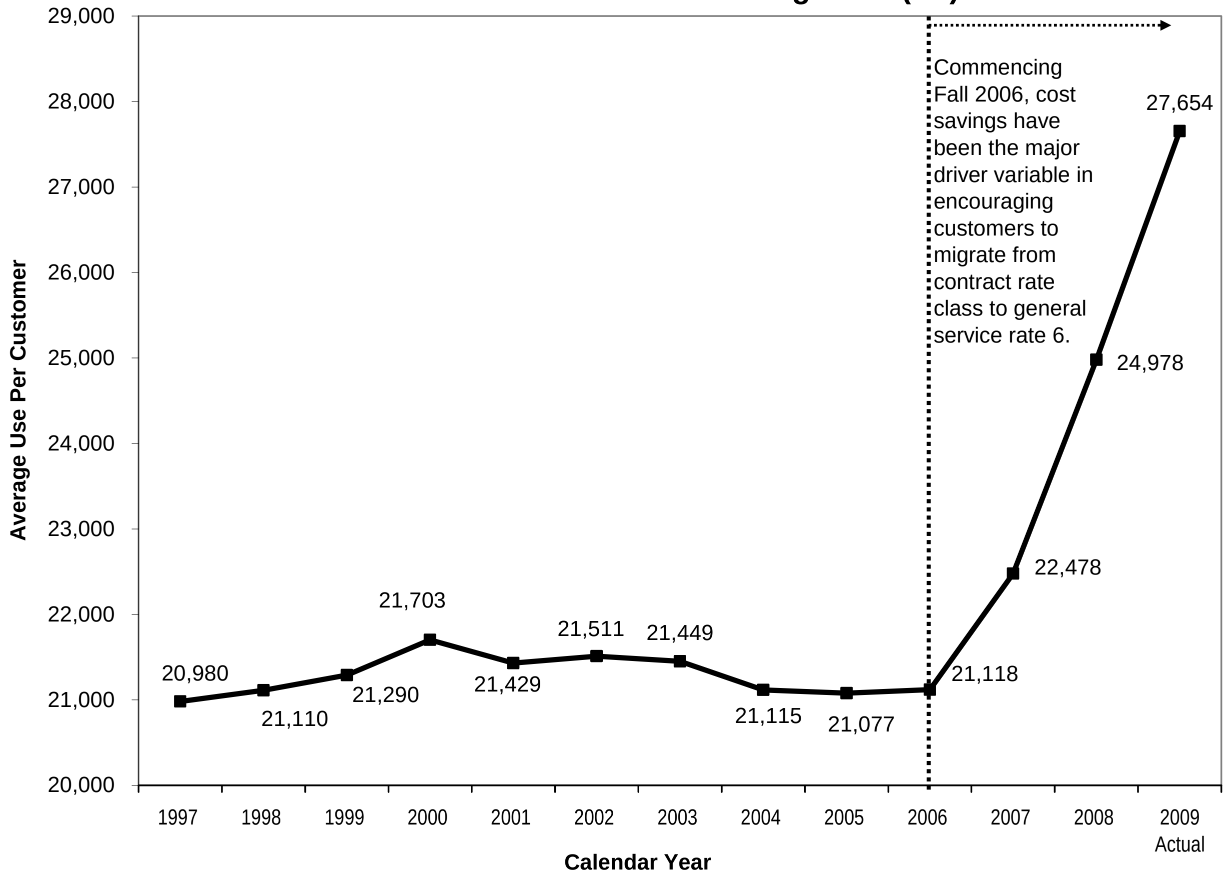
2. Production cuts or plants consolidation due to unfavourable business environment

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	Electronics/High Tech	0.0
	3	Food, Beverage, Drug & Tobacco	0.9
	3	Primary Metal & Machinery	2.3
	1	Pulp & Paper	0.1
	2	Transportation Equipment	0.7
Total	10		4.2

Grand Total	**901**		**561.4**

*The number here only counts the billing account number which is different from meter count. This count does not reflect the timing of the migration as not all customers migrated effective January 1, 2009

Figure 1
Rate 6 Normalized Average Use (m^3)



Witness: I. Chan

**TABLE 2 - CUSTOMER MIGRATION FROM CONTRACT RATE CLASSES TO RATE 6
BETWEEN 2009 ACTUAL AND 2008 ACTUAL**

1. Customers migrated to Rate 6 due to rate design changes

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	9	All Other Industrial	5.9
	468	Apartment	182.6
	1	Asphalt	1.8
	35	Business & Financial Service Industries	21.8
	13	Chemical and Chemical Products	8.9
	1	Construction Industries	0.3
	45	Education Services	18.7
	4	Electronics/High Tech	2.8
	30	Food, Beverage, Drug & Tobacco	14.8
	29	Government Services	19.6
	7	Greenhouses/Agriculture	4.2
	25	Health, Social & Other Services	15.4
	20	Hotels	13.5
	6	Non-Metallic Mineral Products	2.4
	4	Other Utility Industries (Cogen)	6.7
	11	Plastic Products	3.9
	48	Primary Metal & Machinery	29.2
	26	Pulp & Paper	52.0
	12	Recreational & Household Industries	8.6
	4	Rubber Products	2.4
	5	Textile Products	2.2
	19	Transportation and Storage and Utilities	20.2
	43	Transportation Equipment	107.5
	21	Wholesale & Retail Trade	14.3
	5	Wood & Furniture Industries	2.9
Total	891		562.6

2. Production cuts or plants consolidation due to unfavourable business environment

	Number of Customers	Standard Industrial Classification Trade Group	Volume (10^6m^3)
	1	Electronics/High Tech	0.0
	3	Food, Beverage, Drug & Tobacco	1.0
	3	Primary Metal & Machinery	2.3
	1	Pulp & Paper	0.1
	2	Transportation Equipment	0.7
Total	10		4.2
Grand Total	**901**		**566.8**

*The number here only counts the billing account number which is different from meter count. This count does not reflect the timing of the migration as not all customers migrated effective January 1, 2009

SEC INTERROGATORY #7

INTERROGATORY

[Ex. D/1/1] With respect to the financial statements:

a. P. 13. Please provide details of all entries in the financial records relating to the adoption of the new accounting standard with respect to Future Removal and Site Restoration Reserves. Please summarize the impact, if any, of these accounting changes on the regulatory income subject to earnings sharing.

b. P. 16. With respect to the table on this page, please identify the Board-approved deferral or variance account to which each amount relates, and explain the treatment of each amount that does not track to a deferral or variance account.

c. P. 18. Please provide details of the “consulting contract relating to asset management activities”, including the amount and term of the agreement, the parties involved, and any direct or indirect involvement in the project by any entity related to the Applicant.

d. P. 22. Please advise the current dividend rate for the Class D Preference Shares, in percentage terms.

e. P. 23. Please provide a table showing all direct and indirect stock-based compensation expense of the Company in 2009 (with a comparison to 2007 for each category), whether for new grants, existing grants, PSUs, stock-based compensation included in RCAM or other allocated amounts, or any other method by which stock-based compensation is directly or indirectly incurred by the Company. Please provide details on the basis of the calculation of the expense amount in each case, including volatility, price, discount rate, and other assumptions used.

f. P. 25. Please identify the impact, if any, on the earnings available for earnings sharing of the $6.8 million increase in the allowance for doubtful accounts. If there is an impact, please provide details of the rationale for the increase in the allowance.

RESPONSE

a. Please see below for the entries relating to the adoption of the new accounting standard with respect to Future Removal and Site Restoration Reserves. These amounts are included in *Other Long-Term liabilities* on the Company's external financial statements. The entries only impact balance sheet accounts by way of reclassifications and are reversed for rate base calculation purposes. There is no impact in regulatory income subject to earnings sharing as a result of these accounting changes.

	$ millions
Q1 2009 – Initial Adoption Entry	
DR Accumulated Depreciation	639.5
CR Future Removal and Site Restoration Reserves	639.5
Q2 2009 – Quarterly true-up	
DR Accumulated Depreciation	22.5
CR Future Removal and Site Restoration Reserves	22.5
Q3 2009– Quarterly true-up	
DR Accumulated Depreciation	15.2
CR Future Removal and Site Restoration Reserves	15.2
Q4 2009– Quarterly true-up	
DR Accumulated Depreciation	14.4
CR Future Removal and Site Restoration Reserves	14.4

b. Please see Appendix 1 attached. Note that some 2008 account balances were included because they weren't cleared until April/May 2010.

c. The "consulting contract relating to asset management activities" refers to the EnVision contract which has been reviewed in previous regulatory proceedings and was most recently filed in EB-2008-0219 at Exhibit C, Tab 1, Schedule 5 and VECC Interrogatory #16 at Exhibit I, Tab 7, Schedule 16.

d. The current dividend rate for the Class D Preference Shares is 1.80%.

e. Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge Inc. through its various long-term incentive compensation plans. The Company is charged an expense from Enbridge Inc. in relation to these plans. Please see Appendix 2 (attached) for details of the calculation of the expense, which was obtained from Enbridge Inc.

Witness: J. Jozsa

f. Earnings available for earnings sharing implicitly would have been reduced on a pre-tax basis by the $6.8 million increase in the allowance for doubtful accounts. The increase in the allowance is primarily a reflection of the slower collection patterns in 2009 resulting from adverse economic conditions, resulting in higher estimates of amounts which will likely not be collected from customers.

Witness: J. Jozsa

Regulatory Assets/(Liabilities)		Related Board Approved Deferral or Variance Account
Class action lawsuit settlement	20.4	Class Action Suit Deferral Account - Note 1
Ontario hearing costs	5.6	Ontario Hearing Costs Variance Account - Note 2
Purchased gas variance	(226.7)	Purchased Gas Variance Account - Note 3
Unaccounted for gas variance	10.2	Unaccounted for Gas Variance Account - Note 4
Transactional services deferral	(13.6)	Transactional Services Deferral Account - Note 5
Pension plans	(205.1)	Not Applicable - Note 6
OPEB	62.4	Not Applicable - Note 7
Future removal and site restoration reserves	(691.6)	Not Applicable - Note 8
Future income taxes	174.0	Not Applicable - Note 9
Demand Side Management variance	(0.9)	Demand Side Management Variance Account - Note 10
Shared Savings Mechanism	14.1	Shared Savings Mechanism Variance Account - Note 11
Union Gas regulatory deferral	(3.5)	Storage and Transportation Deferral Account - Note 12
Deferred rebate deferral	2.1	Deferred Rebate Account - Note 13
Gas distribution access rule deferral	1.0	Gas Distribution Access Rule Costs Deferral Account - Note 14
Customer care procurement costs	2.9	Not Applicable - Note 15
CIS procurement and selection costs	3.1	Not Applicable - Note 16
Earnings sharing deferral	(24.4)	Earnings Sharing Mechanism Deferral Account - Note 17
Tax rate and rule change variance	(0.3)	Tax Rate and Rule Change Variance Account - Note 18
Average use true-up variance	2.9	Average Use True-Up Variance Account - Note 19
IFRS transition cost deferral	2.1	IFRS Transition Costs Deferral Account - Note 20
Other regulatory assets and liabilities	2.8	Note 21
Subtotal	(862.5)	

Notes:

1. Sum of the December 2009 balance in the 2009 CASDA principal and interest accounts.
2. Sum of the December 2009 balance in the 2009 OHCVA principal and interest accounts $0.5M, the 2008 OHCVA principal and interest accounts $2.3M, and 2010 deferred rated case costs $2.8M. 2010 deferred rate case costs will be expensed during 2010 and be used in the determination as to whether the 2010 OHCVA is needed.
3. Sum of the December 2009 balance in the 2009 PGVA principal and interest accounts ($249.0M) and the 2008 PGVA principal and interest accounts $22.3M.
4. Sum of the December 2009 balance in the 2009 UAFVA principal and interest accounts $9.6M and the 2008 UAFVA principal and interest accounts $0.6M.
5. Sum of the December 2009 balance in the 2009 TSDA principal and interest accounts ($7.1M) and the 2008 TSDA principal and interest accounts ($6.6M).
6. The pension plans' balance represents the regulatory offset to the pension asset recognized in the current year resulting from the adoption of a revised accounting standard in 2009.
7. The OPEB balance represents the regulatory offset to the OPEB liability recognized in the current year resulting from the adoption of a revised accounting standard in 2009.
8. The future removal and site restoration reserves balance results from the adoption of a revised accounting standard in 2009. Enbridge Gas Distribution collects amounts from customers to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment.
9. The future income taxes balance represents the regulatory offset to future income tax liabilities recognized in the current year resulting from adoption of a revised accounting standard in 2009.
10. Sum of the December 2009 balance in the 2008 DSMVA principal and interest accounts ($0.1M) and the 2007 DSMVA principal and interest accounts ($0.7M).
11. Sum of the December 2009 balance in the 2008 SSMVA principal and interest accounts $5.8M and the 2007 SSMVA principal and interest accounts $8.3M.
12. Sum of the December 2009 balance in the 2009 S&TDA principal and interest accounts ($1.6M) and the 2008 S&TDA principal and interest accounts ($1.9M).
13. Sum of the December 2009 balance in the 2009 DRA principal and interest accounts $0.0M and the 2008 DRA principal and interest accounts $2.1M.
14. Sum of the December 2009 balance in the 2009 GDARCDA principal and interest accounts $0.2M and the 2008 GDARCDA principal and interest accounts $0.8M.
15. These costs are charged to earnings over five years to match recovery in rates.
16. These costs are charged to earnings over five years to match recovery in rates.
17. Sum of the December 2009 balance in the 2009 ESMDA principal and interest accounts ($18.8M) and the 2008 ESMDA principal and interest accounts ($5.7M).
18. Sum of the December 2009 balance in the 2009 TRRCVA principal and interest accounts ($0.3M).
19. Sum of the December 2009 balance in the 2009 AUTUVA principal and interest accounts $5.6M and the 2008 AUTUVA principal and interest accounts ($2.7M).
20. Sum of the December 2009 balance in the 2009 IFRSTCDA principal and interest accounts $2.1M.
21. Sum of the December 2009 balance in the 2008 LRAM principal and interest accounts $0.0M, 2007 LRAM principal and interest accounts ($0.3M), 2009 MGPDA principal and interest accounts $0.2M, 2009 OBSDA principal and interest accounts $0.5M, 2009 OBAVA principal and interest accounts $0.5M, 2008 URCMVA principal and interest accounts $0.5M, and other miscellaneous deferred amounts of $1.3M.

Stock Options, PSUs & RSUs Expense Summary
Fiscal 2007 vs Fiscal 2009

($ millions)	**12 Months Ended December 31, 2009**		
	Direct Charge	**Allocation of Costs**	**Total**
Net Stock Options	1.3	1.2	**2.5**
PSUs	1.1	2.2	**3.3**
RSUs	2.6	0.6	**3.2**
PSOPs	-	0.4	**0.4**
Total Stock-Based Compensation Expense	**5.0**	**4.3**	**9.3**

($ millions)	**12 Months Ended December 31, 2007**		
	Direct Charge	**Allocation of Costs**	**Total**
Net Stock Options	1.0	0.8	**1.8**
PSUs	0.4	0.3	**0.7**
RSUs	1.0	0.3	**1.3**
PSOPs	-	0.1	**0.1**
Total Stock-Based Compensation Expense	**2.4**	**1.5**	**3.9**

($ millions)	**Increase/(Decrease) from 2007 to 2009**		
	Direct Charge	**Allocation of Costs**	**Total**
Net Stock Options	0.3	0.4	**0.7**
PSUs	0.7	1.9	**2.6**
RSUs	1.6	0.3	**1.9**
PSOPs	-	0.3	**0.3**
Total Stock-Based Compensation Expense	**2.6**	**2.8**	**5.4**

EXPENSE CALCULATION DETAILS

i) Stock Options	**Fiscal 2009**	**Fiscal 2007**
Number of Units	244,350	132,500
Avg Exercise Price	39.61	38.26
Grant Date Fair Value	6.73	6.16
Risk-free Rate	2.221%	4.11%
Volatility	26.80%	18.10%
Dividend Yield	3.875%	3.22%

ii) PSUs	**Fiscal 2009**			**Fiscal 2007**		
	2009 Grant	**2008 Grant**	**2007 Grant**	**2007 Grant**	**2006 Grant**	**2005 Grant**
Q1 - ending share price	37.40	37.40	37.40	37.66	37.66	37.66
Q2 - ending share price	39.49	39.49	39.49	35.80	35.80	35.80
Q3 - ending share price	41.30	41.30	41.30	36.80	36.80	36.80
Q4 - ending share price	47.40	47.40	47.40	39.10	39.10	39.10
Q1 - Performance multiplier	1.00	1.93	2.00	1.00	1.00	1.00
Q2 - Performance multiplier	2.00	1.93	2.00	1.00	1.00	0.30
Q3 - Performance multiplier	2.00	2.00	2.00	1.00	1.00	0.30
Q4 - Performance multiplier	2.00	2.00	2.00	1.00	1.00	-
Number of Units	6,900			8,900		

iii) RSUs	**Fiscal 2009**	**Fiscal 2007**
Q1 - ending share price	37.40	37.66
Q2 - ending share price	39.49	35.80
Q3 - ending share price	41.30	36.80
Q4 - ending share price	47.40	39.10
Number of Units	61,800	41,050

SEC INTERROGATORY #8

INTERROGATORY

[Ex. D/1/2] With respect to the Management Discussion and Analysis:

a. P. 6. Please run the current weather forecasting model used by the Company and approved by the Board, using actuals to 2008, to forecast the degree days for 2009 and 2010 in the absence of the IRM rules.

b. P. 6-7. Please provide a fuller explanation of the “higher employee related costs, higher customer support related costs, and higher DSM costs” that caused an increase in OM&A from 2008 to 2009, and of the “provision for one-time charges to better align certain operating practices with the Company’s strategy under IR, higher employee related costs, costs relating to the management of fee-for-service energy efficiency initiatives for external parties, and higher DSM costs” that caused an increase in OM&A from 2007 to 2008.

c. P. 20. Please confirm that the impact of the short-term interest rate hedge is to fix short-term interest rate costs at 1.82%.

d. P. 28. Please file a copy of the “detailed IFRS-compliant accounting policies and model financial statement disclosures” referred to on this page.

RESPONSE

a. The Board Approved weather forecasting model(s) used by the Company are the same under either cost of service or the Company’s current incentive model. Consistent with previous filings, the degree day forecast for the Test Year is always based on the latest available full year historical actual data. That means, 2008 actual is the latest available full year historical data when developing 2010 forecast degree days. Similarly, 2007 actual was the latest available full year of historical data when developing the 2009 forecast of degree days.

   As requested, please see the table below for 2009 pro-forma forecast degree days had 2008 full year historical data been available back then.

Witnesses: I. Chan
J. Jozsa
I. McLeod

2009 Degree Days Forecast *using 2008 actuals*

	Environment Canada Degree Days	Gas Supply Degree Days
Central Weather Zone	3,602	3,566
Eastern Weather Zone	4,410	4,371
Niagara Weather Zone	3,496	3,446

b. 2008 to 2009: Higher employee related costs refer to higher benefits, short-term incentives, training and employee relocation expenses. Higher customer care related costs refer to costs relating to the implementation of CIS. Higher costs in the DSM program as a result of budget and target level increases of 5% and 7.5% respectively as determined by the Board in its EB-2006-0021 Decision.

   2007 to 2008: The one-time charges and the higher employee related costs refer primarily to higher stock based and other compensation related expenses. Costs relating to the management of fee-for-service energy efficiency initiatives for external parties are a reference to costs associated with providing services to the Ontario Power Authority, which were absent in the prior period. Higher costs in the DSM program due to budget escalation as per the Board Decision in EB-2006-0021.

c. Confirmed. The short-term interest rates have been hedged with a resulting average interest rate of 1.82% over the life of the hedging program.

d. The detailed IFRS-compliant accounting policies and model financial statement disclosures continue to be subject to significant changes depending on the outcome of the activities of the International Accounting Standards Board (IASB). The IASB issued an exposure draft on Rate Regulated Activities in 2009, but has since delayed its project and is expected to provide an indication of its intended direction on this topic later in 2010. Given the potential pervasive and material impact of rate regulated accounting to the Company's financial statements, there is no way to determine how rate regulated activities should be accounted for under IFRS.

   The Company considers filing of these policies and disclosures as being premature against the above background.

Witnesses: I. Chan
J. Jozsa
I. McLeod