BOARD STAFF INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 1: Is Enbridge's revenue forecast appropriate?

Ref: Ex. C1 /Tab 2/Sch 1 /Table 1

Table 1 shows the trend in the revenues derived from Gas Sales and Transportation of Gas from 2007 to 2013. Please explain the large decrease in Transportation of Gas and the corresponding increase in Gas Sales over the years. In the response, please include a discussion of changes in North American gas markets, changing gas prices, the status of other relevant energy prices, and shifts in customer choice with respect to direct purchase of gas.

RESPONSE

The large decrease in Transportation of Gas from 2007 to 2013 and the corresponding increase in Gas Sales over the years in the table at Exhibit C1, Tab 2, Schedule 1, is primarily due to direct purchase customer migration to system gas over the period from 2007 to 2013 in EGD's franchise areas.

Tables A and B provide the breakdown of system gas and direct purchase volumes and customers for Enbridge. The 2013 volumes forecast of direct purchase only accounts for 61% of 2007 Board approved volumes, which will drive lower transportation revenues. From 2007 to 2011, around 269 thousand direct purchase customers have migrated back to system gas. The migration is expected to continue in 2012 and 2013; about 297 thousand are expected to remain on Direct Purchase in 2013. Meanwhile, over 600 thousand system supply customers are added from 2007 to 2013 due to migration as well as customer additions.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

Table A
Summary of System Supply and Direct Purchase Volumes
(Volumes in $10^6 m^3$)

	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
System Supply	4 780.0	4 998.8	5 254.2	5 417.4	5 386.3	6 236.1	6 613.0	6 989.7
Direct Purchase	6 996.5	7 074.5	6 653.3	5 917.4	5 554.3	5 267.2	4 687.1	4 241.0
Total	11 776.5	12 073.3	11 907.5	11 334.8	10 940.6	11 503.3	11 300.1	11 230.7

Table B
Summary of Average Number of Customer Meters

	2007 Board Approved	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
System Supply	1 113 988	1 117 339	1 182 328	1 248 617	1 373 282	1 521 851	1 595 595	1 723 378
Direct Purchase	709 270	707 450	682 692	638 988	553 012	438 527	389 139	297 584
Total	1 823 258	1 824 789	1 865 020	1 887 605	1 926 294	1 960 378	1 984 734	2 020 962

There are a number of factors that have contributed to the decline in the number of Direct Purchase customers and volumes and the correlating increase in System Supply, particularly in 2010 and 2011.

Warmer temperatures across North America have led to high storage surpluses, putting downward pressure on natural gas prices at a time when shale gas production in the U.S. was soaring. The lack of demand and the surge of supply have contributed to the lowest price levels seen since 1998.

In the last couple of years, a significant number of Direct Purchase customers did not renew their contracts. Further, changes in the Energy Consumer Protection Act resulted in greater clarity and price transparency between the utility rates and a direct purchase contract prices. The combination of these developments contributed to the decrease in Direct Purchase volumes and customers.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 1: Is Enbridge's revenue forecast appropriate?

Ref: Ex. C3 /Tab 1/ Sch 1 / p 5 / line item 23.

With respect to the $15.5 million revenue credit for "Miscellaneous", is this treatment consistent with the Black & Veatch Report filed in the evidence at D2 /Tab 5/ Sch 1?

RESPONSE

The elimination of amounts associated with the Company's unregulated storage division, included within the $15.5 million credit shown in pre-filed evidence at Exhibit C3, Tab 1, Schedule 1, page 5, line 23, do not reflect the proposed treatments identified in the Black & Veatch report. However, the incremental impacts resulting from the adoption of the Black & Veatch report were incorporated within the Impact Statement filed June 1, 2012. Adoption of the Black & Veatch proposals contained in the report resulted in an incremental $0.2M operation and maintenance cost allocation to the unregulated storage division, and was included within the operation and maintenance adjustment shown in Exhibit M1, Tab 1, Schedule 4, pages 1 and 2, line 9.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #3

INTERROGATORY

C - Operating Revenue
Issue 1: Is Enbridge's revenue forecast appropriate?

Ref: Ex. C3 /Tab 5/ Sch 1 /

With respect to the expected 2013 deficiency for the Natural Gas Vehicles Program, please articulate the Company's intentions with respect to the natural gas vehicles program in general, and the program's impacts on the 2013 revenue requirement in particular.

RESPONSE

EGD's ongoing plan is to continue to explore opportunities in new/emerging markets, particularly Return-to-Base Medium Duty Truck fleets. Currently, natural gas has a significant pricing advantage over diesel and gasoline. EGD believes that the current pricing advantage will help in expanding into these new markets and achieve revenue growth in the future. The expected revenue growth will positively impact the Natural Gas Vehicle ("NGV") program in achieving revenue sufficiency over time.

Included within the development of the 2013 revenue requirement is the imputation of a revenue stream equivalent to the NGV Program's gross deficiency, calculated using the Company's required return. This ensures the NGV program does not contribute to the Company's overall revenue deficiency (program revenues are made to equal program costs). The NGV program's return (5.10)% and resultant gross deficiency ($0.5 million) are calculated in Exhibit C3, Tab 5, Schedule 1, while the imputation of revenues is shown in Exhibit C3, Tab 1, Schedule 1, pages 3 and 4, line 9.

Witnesses: F. Ahmad
K. Culbert
M. Tremayne
R. Small

CME INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 1: Is Enbridge's revenue forecast appropriate?

Reference: Exhibit C1, Tab 2, Schedule 1
Exhibit C1, Tab 3, Schedule 1
Exhibit C3, Tab 2, Schedules 1, 2 and 3

We wish to gain a better understanding of the customers that EGD classifies as manufacturers, including the Rate Schedules under which such manufacturers take services, their volumes and their revenues. In this connection, please provide the following information:

(a) Revise Exhibit C3, Tab 2, Schedule 1 to add three (3) additional columns to capture in each column the Customers, Volumes, and Revenues for those customers in each of the line items in the Exhibit that EGD classifies as manufacturers. Please provide the totals for each of the added columns that are intended to provide the manufacturer sub-set of Customer meters, Volumes and Revenues by rate class; and

(b) Please provide the manufacturer sub-set for column 2 of Exhibit C3, Tab 2, Schedule 2, page 1, column 2 of Exhibit C3, Tab 2, Schedule 3, page 1, and column 2 of Exhibit C3, Tab 2, Schedule 4.

RESPONSE

a) EGD classifies all manufacturers as industrial sector. Attachment 1 provides three additional columns for industrial sector on Customers, Volumes and Revenues.

b) Attachments 2, 3, and 4 provide revised columns on Customers, Volumes and Revenues that classify as industrial sector.

Witnesses: R. Lei
S. Qian

CUSTOMER METERS AND VOLUMES BY RATE CLASS
2013 BUDGET

Item No.		Col. 1 Customers (Average)	Col. 2 Volumes (10^6m^3)	Col. 3 Revenues ($Millions)	Col. 4 Industrial Customers (Average)	Col. 5 Industrial Volumes (10^6m^3)	Col. 6 Industrial Revenues ($Millions)
General Service							
1.1.1	Rate 1 - Sales	1 590 583	3 962.5	1 281.5	0	0.0	0.0
1.1.2	Rate 1 - T-Service	271 451	675.0	129.0	0	0.0	0.0
1.1	Total Rate 1	1 862 034	4 637.5	1 410.5	0	0.0	0.0
1.2.1	Rate 6 - Sales	132 728	2 712.5	672.2	4 755	364.9	76.9
1.2.2	Rate 6 - T-Service	25 767	1 933.2	150.3	1 300	293.8	19.6
1.2	Total Rate 6	158 495	4 645.7	822.5	6 055	658.7	96.5
1.3.1	Rate 9 - Sales	8	1.8	0.5	0	0.0	0.0
1.3.2	Rate 9 - T-Service	1	0.2	0.0 **	0	0.0	0.0
1.3	Total Rate 9	9	2.0	0.5	0	0.0	0.0
1.	Total General Service Sales & T-Service	2 020 538	9 285.2	2 233.5	6 055	658.7	96.5
Contract Sales							
2.1	Rate 100	0	0.0	0.0	0	0.0	0.0
2.2	Rate 110	36	66.8	11.8	30	59.9	10.5
2.3	Rate 115	2	2.8	0.5	0	0.0	0.0
2.4	Rate 135	1	0.6	0.1	1	0.6	0.1
2.5	Rate 145	13	24.8	4.2	2	3.0	0.5
2.6	Rate 170	6	54.8	8.1	1	6.1	0.9
2.7	Rate 200	1	163.1	23.7	0	0.0	0.0
2.	Total Contract Sales	59	312.9	48.4	34	69.6	12.0
Contract T-Service							
3.1	Rate 100	0	0.0	0.0	0	0.0	0.0
3.2	Rate 110	165	420.8	13.1	135	363.5	11.3
3.3	Rate 115	28	536.6	6.9	21	282.4	3.6
3.4	Rate 125	5	0.0 *	10.9	0	0.0 *	0.0
3.5	Rate 135	37	54.6	1.6	37	54.6	1.6
3.6	Rate 145	95	128.0	3.3	46	52.1	1.2
3.7	Rate 170	32	461.6	(0.6)	20	246.2	(0.9)
3.8	Rate 300	3	31.0	0.2	0	0.0	0.0
3.9	Rate 315	0	0.0	0.0	0	0.0	0.0
3.	Total Contract T-Service	365	1 632.6	35.4	259	998.8	16.8
4.	Total Contract Sales & T-Service	424	1 945.5	83.8	293	1 068.4	28.8
5.	Total	2 020 962	11 230.7	2 317.3	6 348	1 727.1	125.3

* There is no distribution volume for Rate 125 customers.
** Less than $50,000.

COMPARISON OF AVERAGE CUSTOMER METERS BY RATE CLASS
2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE - INDUSTRIAL SECTOR

Item No.		Col. 1 2013 Budget	Col. 2 2012 Bridge Year Estimate	Col. 3 2013 Budget Over (Under) 2012 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	0	0	0
1.1.2	Rate 1 - T-Service	0	0	0
1.1	Total Rate 1	0	0	0
1.2.1	Rate 6 - Sales	4 755	4 670	85
1.2.2	Rate 6 - T-Service	1 300	1 396	(96)
1.2	Total Rate 6	6 055	6 066	(11)
1.3.1	Rate 9 - Sales	0	0	0
1.3.2	Rate 9 - T-Service	0	0	0
1.3	Total Rate 9	0	0	0
1.	Total General Service Sales & T-Service	6 055	6 066	(11)
Contract Sales				
2.1	Rate 100	0	0	0
2.2	Rate 110	30	28	2
2.3	Rate 115	0	0	0
2.4	Rate 135	1	1	0
2.5	Rate 145	2	2	0
2.6	Rate 170	1	1	0
2.7	Rate 200	0	0	0
2.	Total Contract Sales	34	32	2
Contract T-Service				
3.1	Rate 100	0	0	0
3.2	Rate 110	135	137	(2)
3.3	Rate 115	21	21	0
3.4	Rate 125	0	0	0
3.5	Rate 135	37	37	0
3.6	Rate 145	46	44	2
3.7	Rate 170	20	20	0
3.8	Rate 300	0	0	0
3.9	Rate 315	0	0	0
3.	Total Contract T-Service	259	259	0
4.	Total Contract Sales & T-Service	293	291	2
5.	Total	6 348	6 357	(9)

COMPARISON OF GAS SALES AND
TRANSPORTATION VOLUME BY RATE CLASS
2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE - INDUSTRIAL SECTOR
($10^6 m^3$)

Item No.		Col. 1 2013 Budget	Col. 2 2012 Bridge Year Estimate	Col. 3 2013 Budget Over (Under) 2012 Estimate (1-2)
General Service				
1.1.1	Rate 1 - Sales	0.0	0.0	0.0
1.1.2	Rate 1 - T-Service	0.0	0.0	0.0
1.1	Total Rate 1	0.0	0.0	0.0
1.2.1	Rate 6 - Sales	364.9	380.0	(15.1)
1.2.2	Rate 6 - T-Service	293.8	316.6	(22.8)
1.2	Total Rate 6	658.7	696.6	(37.9)
1.3.1	Rate 9 - Sales	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0
1.3	Total Rate 9	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	658.7	696.6	(37.9)
Contract Sales				
2.1	Rate 100	0.0	0.0	0.0
2.2	Rate 110	59.9	57.3	2.6
2.3	Rate 115	0.0	0.0	0.0
2.4	Rate 135	0.6	0.6	0.0
2.5	Rate 145	3.0	4.4	(1.4)
2.6	Rate 170	6.1	6.2	(0.1)
2.7	Rate 200	0.0	0.0	0.0
2.	Total Contract Sales	69.6	68.5	1.1
Contract T-Service				
3.1	Rate 100	0.0	0.0	0.0
3.2	Rate 110	363.5	366.1	(2.6)
3.3	Rate 115	282.4	282.2	0.2
3.4	Rate 125	0.0 *	0.0 *	0.0
3.5	Rate 135	54.6	54.6	0.0
3.6	Rate 145	52.1	51.3	0.8
3.7	Rate 170	246.2	247.9	(1.7)
3.8	Rate 300	0.0	0.0	0.0
3.9	Rate 315	0.0	0.0	0.0
3.	Total Contract T-Service	998.8	1 002.1	(3.3)
4.	Total Contract Sales & T-Service	1 068.4	1 070.6	(2.2)
5.	Total	1 727.1	1 767.2	(40.1)

* There is no distribution volume for Rate 125 customers.

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2013 BUDGET AND 2012 BRIDGE YEAR ESTIMATE - INDUSTRIAL SECTOR
($ MILLIONS)

		Col. 1	Col. 2	Col. 3	
Item No.		2013 Budget	2012 Bridge Year Estimate	2013 Budget Over (Under) 2012 Estimate (1-2)	
General Service					
1.1.1	Rate 1 - Sales	0.0	0.0	0.0	
1.1.2	Rate 1 - T-Service	0.0	0.0	0.0	
1.1	Total Rate 1	0.0	0.0	0.0	
1.2.1	Rate 6 - Sales	76.9	95.2	(18.3)	
1.2.2	Rate 6 - T-Service	19.6	20.9	(1.3)	
1.2	Total Rate 6	96.5	116.1	(19.6)	
1.3.1	Rate 9 - Sales	0.0	0.0	0.0	
1.3.2	Rate 9 - T-Service	0.0	0.0	0.0	
1.3	Total Rate 9	0.0	0.0	0.0	
1.	Total General Service Sales & T-Service	96.5	116.1	(19.6)	
Contract Sales					
2.1	Rate 100	0.0	0.0	0.0	
2.2	Rate 110	10.5	12.4	(1.9)	
2.3	Rate 115	0.0	0.0	0.0	
2.4	Rate 135	0.1	0.1	0.0	*
2.5	Rate 145	0.5	0.9	(0.4)	
2.6	Rate 170	0.9	1.2	(0.3)	
2.7	Rate 200	0.0	0.0	0.0	
2.	Total Contract Sales	12.0	14.6	(2.6)	
Contract T-Service					
3.1	Rate 100	0.0	0.0	0.0	
3.2	Rate 110	11.3	13.3	(2.0)	
3.3	Rate 115	3.6	3.7	(0.1)	
3.4	Rate 125	0.0	0.0	0.0	
3.5	Rate 135	1.6	1.6	0.0	*
3.6	Rate 145	1.2	1.2	0.0	
3.7	Rate 170	(0.9)	(0.7)	(0.2)	
3.8	Rate 300	0.0	0.0	0.0	
3.9	Rate 315	0.0	0.0	0.0	
3.	Total Contract T-Service	16.8	19.1	(2.3)	
4.	Total Contract Sales & T-Service	28.8	33.7	(4.9)	
5.	Total	125.3	149.8	(24.5)	

* Less than $50,000.

CCC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 1: Is Enbridge's revenue forecast appropriate?

Ref: C1/T2/S1/p. 1

Please re-cast Table 1 (Revenue Forecast) to include 2007 to 2010 actuals.

RESPONSE

Please see Table 1 for Revenue Forecast, including 2007 to 2010 actuals:

Table 1
Revenue Forecast
($ millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
	2007 Budget Board Approved	2007 Actual Year	2008 Actual Year	2009 Actual Year	2010 Actual Year	2011 Actual Year	2012 Estimate Bridge Year	2013 Budget Year
1.0 Gas Sales	2,377.1	2,274.3	2,353.4	2,221.6	1,988.0	1,978.4	2,158.8	2,004.1
2.0 Transportation of Gas	740.2	732.0	747.3	627.7	460.1	411.2	361.4	313.9
3.0 Transmission, Compression and Storage	1.7	1.1	1.8	1.6	1.4	1.5	1.7	1.7
4.0 Other Operating Revenue	35.1	39.6	43.2	48.4	53.8	41.4	40.1	39.0
5.0 Total Operating Revenue	3,154.1	3,047.0	3,145.7	2,899.3	2,503.3	2,432.5	2,562.0	2,358.7

Witnesses: R. Lei
S. Qian

CCC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

Ref: C1/T3/S1

Please re-cast Table 1 (Summary of Gas sales and Transportation Volumes and Customers) to include 2017-2011 actuals.

RESPONSE

Please see Table 1 for Summary of Gas Sales and Transportation Volumes and Customers including 2007 - 2011 actual amounts.

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

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
General Service Volumes	8 314.8	8 806.0	9 129.2	8 757.0	9 420.8	9 356.7	9 285.2
Contract Market Volumes	3 758.5	3 101.5	2 205.6	2 183.6	2 082.5	1 943.4	1 945.5
Total Volumes, Gas Sales and Transportation	12 073.3	11 907.5	11 334.8	10 940.6	11 503.3	11 300.1	11 230.7
Customers, Gas Sales and Transportation (Average)	1 824 789	1 865 020	1 887 605	1 926 294	1 960 378	1 984 734	2 020 962

Witnesses: R.Lei
S. Qian

CCC INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

Ref: C1/T3/S1

During the IRM term did EGD prepare an annual gas volume forecast. If so, what methodology was employed? If so, please provide those forecasts for each year 2007-2011

RESPONSE

Yes, the gas volume forecast was prepared using the Board approved methodology and the result was approved by the Board annually as part of the rate case filings during the IRM term. Please refer to the following table.

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

	2007 Board Approved Budget	2008 Board Approved Budget	2009 Board Approved Budget	2010 Board Approved Budget	2011 Board Approved Budget
General Service Volumes	7 642.2	8 288.0	9 083.2	9 083.5	9 283.4
Contract Market Volumes	4 134.3	3 355.2	2 316.6	2 008.6	2 022.9
Total Volumes, Gas Sales and Transportation	11 776.5	11 643.2	11 399.8	11 092.1	11 306.3

Witnesses: R.Lei
S. Qian

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

Ref: Exhibit C1, Tab 3, Schedule 1

a) Please confirm that the 2011 data in Table 1 is actual data. If this cannot be confirmed, please update Table 1 to include actual 2011 data.

b) Please update Table 3 in Appendix A to reflect actual data for 2011.

RESPONSE

a) Table 1 has been updated with 2011 actual data and 2013 updated budget data.

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

	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
General Service Volumes	8 757.0	9 420.8	9 356.7	9 285.2
Contract Market Volumes	2 183.6	2 082.5	1 943.4	1 945.5
Total Volumes, Gas Sales and Transportation	10 940.6	11 503.3	11 300.1	11 230.7
Customers, Gas Sales and Transportation (Average)	1 926 294	1 960 378	1 984 734	2 020 962

Witnesses: R. Lei
S. Qian

b) The following Table 3 includes actual data for 2011.

TABLE 3 - GENERAL SERVICE AND CONTRACT MARKET CUSTOMERS

	Test Year	Col. 1 Actual Customers	Col. 2 Board Approved Customers	Col. 3 Variance Customers (1-2)	Col. 4 %Variance Customers (3/2)*100
FISCAL YEAR	1995	1,222,293	1,216,511	5,782	0.5%
	1996	1,263,290	1,262,815	475	0.0%
	1997	1,312,434	1,309,752	2,682	0.2%
	1998	1,364,350	1,353,178	11,172	0.8%
	1999	1,414,788	1,417,832	(3,044)	-0.2%
	2000[a]	1,464,738	1,468,915	(4,177)	-0.3%
	2001	1,519,039	1,514,710	4,329	0.3%
	2002	1,566,710	1,565,017	1,693	0.1%
	2003	1,622,016	1,615,037	6,979	0.4%
	2004*	1,676,380	1,672,586	3,794	0.2%
	2005[b]	1,724,716	1,718,766	5,950	0.3%
CALENDAR YEAR	2006	1,782,813	1,792,615	(9,802)	-0.5%
	2007	1,824,789	1,823,258	1,531	0.1%
	2008	1,865,020	1,864,047	973	0.1%
	2009	1,887,605	1,906,437	(18,832)	-1.0%
	2010	1,926,294	1,931,528	(5,234)	-0.3%
	2011	1,960,378	1,965,538	(5,160)	-0.3%

* 2004 Bridge Year Estimate from RP-2003-0203 was reported at column 2 because Board Approved numbers are not available since there was no 2004 Board Approved Volumes Budget due to the nature of the 2004 Rate Application. Please see RP-2003-0048, Exhibit A, Tab 3, Schedule 1 for the rationale for implementing this new approach.

a. In consequence of the ADR settlement agreement in capital expenditure, there was a reduction in customers of 2,251 to the board approved budget numbers.

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

Witnesses: R. Lei
S. Qian

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

Ref: Exhibit C1, Tab 2, Schedule 1, Updated &
Exhibit C2, Tab 1, Schedule 1, Updated

a) Please confirm that the updated revenue forecasts shown in Exhibit C1, Tab 2, Schedule 1, Updated, reflects the updated key economic assumptions shown in Exhibit C2, Tab 1, Schedule 1, Updated. If this cannot be confirmed, please update the revenue and volume forecast to reflect the updated economic assumptions.

b) Please explain why EGD has not updated the interest rate and exchange rate outlook. Please provide the interest rate and exchange rate outlook based on the Spring 2012 Economic Outlook. Do any changes in these forecasts have an impact on the volume forecast? If yes, please provide details on the impact of the volume forecast.

RESPONSE

a) EGD confirms that the 2013 revenue budgets shown in Exhibit C1, Tab 2, Schedule 1, updated on June 1, 2012, reflects the updated key economic assumptions shown in Exhibit C2, Tab 1, Schedule 1, updated on June 1, 2012.

b) The Interest Rate and Exchange Rate Outlook was not updated for Spring 2012. The Company decided to only update forecasts that have an impact on the volumetric projections. In that regard, an exchange rate consensus forecast was used to convert natural gas price projections. None of the interest rates are used in any of the models to forecast volumes.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

FRPO INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

Reference: C1 , Tab 3, Schedule 1, page 10, Table 3

Please explain the Gas Prices impact on Total Volume.

a. Please ensure that the explanation provides the underlying assumptions in gas prices and the elasticity used including the basis for that figure.

RESPONSE

The gas price assumptions to derive the volume impact are listed at Exhibit C2, Tab 1, Schedule 1. As stated in Exhibit C1, Tab 3, Schedule 1, the general service volumes are derived using the average use forecasting models and the customer additions and unlocks budget. The average use models are Company developed regression models to quantify the impact of various driver variables including gas price on the average use forecast per customer for general service. The details of the model are described at Exhibit C2, Tab 2, Schedule 1. The gas price impact on total volume is derived based on the gas price impact analysis from the average use model and the corresponding customer budget.

To develop the average use forecast, input data were updated to include the latest actual information as well as the latest projections for driver variables. The models were then subjected to a battery of tests to ensure that they continued to be statistically valid and that forecast accuracy was at least maintained, or improved.

The Company generated the updated residential average use forecast with updated residential gas price assumptions of a 9.6% decline in 2012 from 2011, and a subsequent increase of 18.2% in 2013.

The coefficients of the real gas price variable in the Rate 1 average use equations, as shown in Table 5, at Exhibit C2, Tab 2, Schedule 1, pages 11 and 12, can be interpreted as the price elasticity, and shows the relationship between gas prices and average use demand, for each region in the Company's franchise area. The coefficients

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

of real gas price variables in the table range from -0.03 to -0.10, indicating that a 1% increase in real gas price would translate to a decline in average use between 0.03% and 0.10%, all other variables being equal. Taking the Central region as an example, the coefficient of 0.06 is interpreted to show that a 1% increase in real gas price would lead to a 0.06% decline in the Central region's average use, assuming all other variables in the model are held constant.

Overall, the impact of a 1% increase in real gas price would lead to an incremental 0.04% decline in the residential average use, assuming all other variables in the model are held constant.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

FRPO INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

Reference: C1 , Tab 3, Schedule 1, page 11-12, paragraph 21

For the large distributed energy plant, what are the prospects with continued low natural gas prices that this plant could be bought and continue to consume.

a. Please provide the information that the company currently has on this plant.

RESPONSE

a) The updated 2013 Test Year volume forecast filed on June 1, 2012, at Exhibit C3, Tab 2, Schedule 1, has included the distribution volume of this large distributed energy plant. The contract market volume budget has been updated to 1,945.5 10^6m^3.

Witnesses: R. Lei
S. Qian

JUST ENERGY INTERROGATORY #1

INTERROGATORY

C- Operating Revenue
Issue 2: Is Enbridge's gas volume forecast appropriate?

a) Please provide a breakdown of the annual level of direct purchase and system supply customers in terms of volume and numbers for the past three years with estimates for the next two years.

Please provide the breakdown requested in a) above showing the split in terms of volume and numbers for the past three years and estimates for the next two years separated into residential and commercial customers.

RESPONSE

a) Table 1 provides the volumes summary of direct purchase and system supply customers.

Table 1
Summary of System Supply and Direct Purchase Volumes
(Volumes in $10^6 m^3$)

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
System Supply	5 417.4	5 386.3	6 236.1	6 613.0	6 989.7
Direct Purchase	5 917.4	5 554.3	5 267.2	4 687.1	4 241.0
Total	11 334.8	10 940.6	11 503.3	11 300.1	11 230.7

Witnesses: R. Lei
S. Qian

Table 2 provides the number of direct purchase and system supply customers.

Table 2
Summary of Average Number of Customer Meters

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
System Supply	1 248 617	1 373 282	1 521 851	1 595 595	1 723 378
Direct Purchase	638 988	553 012	438 527	389 139	297 584
Total	1 887 605	1 926 294	1 960 378	1 984 734	2 020 962

Table 3 provides the volumes summary of direct purchase and system supply by customer type.

Table 3
Summary of System Supply and Direct Purchase Volumes
(Volumes in $10^6 m^3$)

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
Residential					
System Supply	3 119.7	3 119.2	3 601.7	3 693.2	3 962.5
Direct Purchase	1 625.8	1 294.7	1 098.2	890.1	675.0
Total	4 745.5	4 413.9	4 699.9	4 583.3	4 637.5
Commercial					
System Supply	1 578.9	1 481.8	1 768.7	1 975.7	2 073.8
Direct Purchase	1 801.1	1 773.2	1 684.6	1 583.7	1 470.9
Total	3 380.0	3 255.0	3 453.3	3 559.4	3 544.7
Apartment & Industrial					
System Supply	718.8	785.3	865.7	944.1	953.4
Direct Purchase	2 490.5	2 486.4	2 484.4	2 213.3	2 095.1
Total	3 209.3	3 271.7	3 350.1	3 157.4	3 048.5

Witnesses: R. Lei
S. Qian

Table 4 provides the number of residential and commercial customers by direct purchase and system supply.

Table 4
Summary of Average Number of Customer Meters

	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year Estimate	2013 Budget
Residential					
System Supply	1 140 498	1 260 809	1 399 998	1 467 726	1 590 583
Direct Purchase	591 689	511 694	402 580	359 070	271 451
Total	1 732 187	1 772 503	1 802 578	1 826 796	1 862 034
Commercial					
System Supply	101 156	105 023	113 563	119 233	123 755
Direct Purchase	40 754	35 461	30 442	24 890	21 408
Total	141 910	140 484	144 005	144 123	145 163
Apartment & Industrial					
System Supply	6 963	7 450	8 290	8 636	9 040
Direct Purchase	6 545	5 857	5 505	5 179	4 725
Total	13 508	13 307	13 795	13 815	13 765

Witnesses: R. Lei
S. Qian

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Operating Revenue
Issue 3: Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

Ref: Exhibit C2, Tab 3, Schedule 1

a) Please confirm that the "out of sample" forecasts shown in Tables 1, 5 and 9 are based on a three year ahead forecast. For example, the 2010 forecast is based on data up to and including 2007.

b) Please provide the 2013 forecast for each methodology shown in Tables, 1, 5 and 9.

c) Please add 2011 actual data to each of Tables 1, 5 and 9 and update Tables 2 through 4, 6 through 8 and 10 through 12 to reflect actual 2011 data.

RESPONSE

a) The out-of-sample forecasts contained in Tables 1, 5, and 9 are based on a two year-ahead forecast. Using the 2010 forecast as an example, it was generated using actual data up to and including 2008.

   At the time of the 2013 application, 2010 was the last complete year of actual data. Hence, the 2013 forecast was the only year with the exception as it was generated with a three year-ahead forecast using data up to and including 2010.

   The 2013 forecast has been updated at Exhibit C2, Tab 3, Schedule 2 to include actual data up to and including 2011 so that it is consistent with the rest of the forecasts using the two year-ahead approach.

b) Please see the 2013 forecasts included in Tables 1, 5, and 9 as part of the response to part c) of this interrogatory.

c) The Company used the same approach that underlies the Board-Approved methodology from the 2007 Test Year (EB-2006-0034) to update its 2013 forecasts

Witnesses: H. Sayyan
M. Suarez

by including actual data for 2011 for each of the weather zones. This approach evaluates the same nine forecasting methods from the 2007 test year, forecasts of which were measured using accuracy statistics, and ranked based on how well each method met the criteria of accuracy, symmetry, and stability. Please see the description of the Degree Day Forecast Methodology and the review criteria as contained in paragraphs 3 – 8, Exhibit C2, Tab 3, Schedule 1, page 3.

The same evaluation process was the starting point in this update. While the analyses show continued support for the methodologies proposed in the original application, the inclusion of the 2011 actual showed weaker results. The Company sought to test these results by applying the evaluation approach consistently to all years for which data are available.

Tables 1 through 12 show the results of updating the evaluation approach with 2011 data. Following that is an explanation of the extra validation applied and how the original proposal continues to be supported.

Table 1

Actual and Forecast Central weather zone Environment Canada Degree Days ('out-of-sample'), 1990 to 2011

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 11*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*
Calendar Year	Actual	Naïve	10-yr MA	20-yr MA	20-yr Trend	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe
1990	3,631	4,076	4,110	4,188	4,003	4,179	4,091	4,019	3,964	3,981
1991	3,686	4,250	4,111	4,186	4,029	4,187	4,108	4,088	4,098	4,176
1992	4,112	3,631	4,036	4,152	3,927	4,174	4,050	3,984	3,878	3,918
1993	4,180	3,686	3,990	4,128	3,829	4,166	3,997	3,930	3,692	3,689
1994	4,115	4,112	3,982	4,105	3,883	4,166	4,025	3,996	3,831	3,830
1995	4,040	4,180	3,994	4,117	3,879	4,168	4,023	4,067	3,962	3,943
1996	4,177	4,115	3,991	4,111	3,894	4,166	4,030	4,087	4,017	4,019
1997	4,026	4,040	3,984	4,113	3,865	4,155	4,010	4,109	4,032	4,029
1998	3,220	4,177	4,003	4,098	3,926	4,152	4,039	4,140	4,067	4,074
1999	3,539	4,026	4,029	4,090	3,922	4,143	4,032	4,120	4,037	4,031
2000	3,826	3,220	3,944	4,027	3,787	4,107	3,947	3,928	3,829	3,768
2001	3,420	3,539	3,873	3,992	3,710	4,082	3,896	3,834	3,768	3,688
2002	3,630	3,826	3,892	3,964	3,727	4,065	3,896	3,814	3,779	3,762
2003	3,982	3,420	3,866	3,928	3,634	4,041	3,837	3,693	3,557	3,570
2004	3,798	3,630	3,817	3,900	3,604	4,009	3,807	3,640	3,548	3,603
2005	3,797	3,982	3,797	3,896	3,644	4,010	3,827	3,813	3,711	3,775
2006	3,378	3,798	3,766	3,878	3,656	3,996	3,826	3,848	3,737	3,802
2007	3,722	3,797	3,741	3,863	3,668	3,989	3,828	3,860	3,739	3,831
2008	3,837	3,378	3,662	3,832	3,581	3,952	3,766	3,748	3,655	3,650
2009	3,836	3,722	3,631	3,830	3,548	3,937	3,742	3,745	3,670	3,648
2010	3,501	3,837	3,693	3,818	3,582	3,915	3,749	3,777	3,703	3,716
2011	3,648	3,836	3,722	3,798	3,642	3,902	3,772	3,813	3,739	3,768
2013F		3,648	3,713	3,789	3,512	3,856	3,684	3,736	3,664	3,660

Table 2

The Central Degree Day: Out-of-sample forecast performance, all available years (1990 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.7%	9	11.1%	8	2.0%	4	59%	3	284	9	33	*8*
10-yr MA	6.2%	1	8.6%	2	3.5%	5	59%	3	145	4	15	*1*
20-yr MA	6.8%	4	9.9%	7	6.4%	8	73%	8	133	3	30	*7*
20-yr Trend	6.5%	3	7.9%	1	0.3%	1	36%	6	150	5	16	*2*
30-yr MA	8.4%	8	11.3%	9	8.4%	9	91%	9	97	1	36	*9*
50-50: 20-yr Trend & 30-yr MA	6.2%	2	8.8%	3	4.3%	7	59%	3	121	2	17	*3*
de Bever	6.8%	5	9.4%	6	4.1%	6	64%	6	151	6	29	*6*
de Bever with Trend	7.0%	6	9.1%	4	1.6%	2	55%	2	165	7	21	*4*
Energy Probe	7.1%	7	9.2%	5	2.0%	3	50%	1	168	8	24	*5*

Witnesses: H. Sayyan
M. Suarez

Table 3

The Central Degree Day: Out-of-sample forecast performance, recent ten year period (2002 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.3%	8	8.4%	8	0.6%	3	60%	3	192	9	31	*8*
10-yr MA	4.0%	1	5.3%	1	1.4%	4	70%	5	86	7	18	*1*
20-yr MA	4.8%	4	6.6%	7	4.5%	8	70%	5	52	3	27	*7*
20-yr Trend	4.7%	3	5.5%	2	2.0%	6	30%	5	52	2	18	*1*
30-yr MA	7.5%	9	8.9%	9	7.5%	9	100%	9	54	4	40	*9*
50-50: 20-yr Trend & 30-yr MA	4.3%	2	5.7%	3	2.7%	7	70%	5	48	1	18	*1*
de Bever	5.2%	5	6.3%	5	1.9%	5	60%	3	69	5	23	*5*
de Bever with Trend	5.2%	6	6.1%	4	0.5%	2	50%	1	78	6	19	*4*
Energy Probe	5.4%	7	6.4%	6	0.3%	1	50%	1	89	8	23	*5*

Table 4

The Central Degree Day: Out-of-sample forecast performance, recent five year period (2007 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	6.3%	9	7.4%	9	0.4%	2	60%	1	193	9	30	*7*
10-yr MA	3.6%	4	4.1%	3	0.4%	3	60%	1	45	5	16	*3*
20-yr MA	3.4%	1	4.8%	7	3.3%	8	60%	1	24	1	18	*4*
20-yr Trend	3.6%	5	4.7%	6	2.7%	7	20%	8	49	7	33	*8*
30-yr MA	6.3%	8	7.2%	8	6.3%	9	100%	9	34	2	36	*9*
50-50: 20-yr Trend & 30-yr MA	3.5%	2	4.0%	1	1.8%	5	60%	1	34	3	12	*2*
de Bever	4.2%	6	4.6%	5	2.3%	6	60%	1	48	6	24	*5*
de Bever with Trend	3.6%	3	4.0%	2	0.1%	1	60%	1	38	4	11	*1*
Energy Probe	4.4%	7	4.6%	4	0.5%	4	60%	1	79	8	24	*5*

Witnesses: H. Sayyan
M. Suarez

Table 5

Actual and Forecast Eastern weather zone Environment Canada Degree Days ('out-of-sample'), 1990 to 2011

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 11*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*
Calendar Year	Actual	Naïve	10-yr MA	20-yr MA	20-yr Trend	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe
1990	4,250	4,640	4,579	4,670	4,483	4,688	4,585	4,620	4,490	4,472
1991	4,303	4,931	4,613	4,682	4,543	4,695	4,619	4,674	4,639	4,648
1992	4,861	4,250	4,546	4,649	4,479	4,688	4,583	4,599	4,524	4,525
1993	4,780	4,303	4,533	4,625	4,424	4,679	4,551	4,538	4,453	4,453
1994	4,730	4,861	4,554	4,617	4,526	4,680	4,603	4,628	4,549	4,548
1995	4,585	4,780	4,579	4,635	4,535	4,675	4,605	4,665	4,585	4,579
1996	4,603	4,730	4,598	4,635	4,567	4,680	4,624	4,687	4,567	4,533
1997	4,786	4,585	4,591	4,639	4,540	4,673	4,607	4,687	4,538	4,531
1998	3,828	4,603	4,601	4,618	4,581	4,670	4,626	4,673	4,541	4,546
1999	4,137	4,786	4,647	4,628	4,614	4,667	4,641	4,678	4,604	4,611
2000	4,543	3,828	4,566	4,572	4,484	4,635	4,559	4,512	4,515	4,417
2001	4,115	4,137	4,486	4,550	4,392	4,617	4,504	4,570	4,420	4,395
2002	4,381	4,543	4,515	4,531	4,440	4,605	4,522	4,566	4,446	4,447
2003	4,715	4,115	4,497	4,515	4,338	4,582	4,460	4,408	4,341	4,357
2004	4,637	4,381	4,449	4,501	4,327	4,561	4,444	4,380	4,339	4,412
2005	4,421	4,715	4,442	4,510	4,377	4,571	4,474	4,538	4,430	4,530
2006	4,037	4,637	4,433	4,516	4,408	4,568	4,488	4,586	4,436	4,525
2007	4,447	4,421	4,416	4,504	4,406	4,565	4,485	4,572	4,427	4,503
2008	4,488	4,037	4,360	4,480	4,306	4,532	4,419	4,490	4,394	4,357
2009	4,534	4,447	4,326	4,486	4,279	4,527	4,403	4,506	4,426	4,401
2010	3,973	4,488	4,392	4,479	4,299	4,512	4,406	4,510	4,430	4,430
2011	4,136	4,534	4,432	4,459	4,370	4,510	4,440	4,528	4,442	4,462
2013F		4,136	4,377	4,437	4,154	4,469	4,311	4,388	4,334	4,328

Table 6

The Eastern Degree Day: Out-of-sample forecast performance, all available years (1990 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.7%	9	10.3%	9	2.0%	4	59%	4	285	9	35	*8*
10-yr MA	5.7%	1	7.3%	3	2.3%	5	50%	1	90	7	17	*2*
20-yr MA	5.7%	4	7.7%	6	3.7%	7	64%	6	72	2	25	*6*
20-yr Trend	5.8%	5	7.2%	1	0.9%	1	41%	4	100	8	19	*4*
30-yr MA	6.1%	7	8.3%	7	4.8%	9	68%	9	65	1	33	*7*
50-50: 20-yr Trend & 30-yr MA	5.7%	2	7.5%	5	2.9%	6	64%	6	80	4	23	*5*
de Bever	6.4%	8	8.4%	8	3.9%	8	64%	6	87	6	36	*9*
de Bever with Trend	5.7%	3	7.3%	2	1.7%	2	50%	1	82	5	13	*1*
Energy Probe	6.0%	6	7.4%	4	1.9%	3	50%	1	79	3	17	*2*

Witnesses: H. Sayyan
M. Suarez

Table 7

The Eastern Degree Day: Out-of-sample forecast performance, recent ten year period (2002 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.9%	9	9.1%	9	1.7%	4	50%	1	213	9	32	*7*
10-yr MA	4.8%	2	5.8%	1	1.4%	3	50%	1	57	6	13	*1*
20-yr MA	4.8%	1	6.4%	5	3.1%	7	60%	4	22	1	18	*4*
20-yr Trend	5.1%	5	5.9%	2	0.2%	1	40%	4	53	5	17	*3*
30-yr MA	5.3%	6	7.0%	7	4.3%	9	70%	8	31	2	32	*7*
50-50: 20-yr Trend & 30-yr MA	4.9%	3	6.1%	3	2.1%	6	60%	4	39	3	19	*5*
de Bever	5.9%	8	7.5%	8	3.4%	8	70%	8	68	8	40	*9*
de Bever with Trend	5.0%	4	6.3%	4	1.1%	2	50%	1	40	4	15	*2*
Energy Probe	5.5%	7	6.7%	6	1.8%	5	60%	4	63	7	29	*6*

Table 8

The Eastern Degree Day: Out-of-sample forecast performance, recent five year period (2007 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.0%	9	8.5%	9	2.0%	3	40%	1	199	9	31	*7*
10-yr MA	5.2%	5	6.2%	3	1.9%	2	40%	1	43	6	17	*5*
20-yr MA	4.6%	1	6.7%	6	4.1%	7	60%	1	16	1	16	*4*
20-yr Trend	4.9%	4	5.4%	1	0.7%	1	40%	1	54	7	14	*1*
30-yr MA	5.3%	6	7.4%	7	5.2%	9	80%	8	22	3	33	*8*
50-50: 20-yr Trend & 30-yr MA	4.7%	2	6.1%	2	2.9%	5	60%	1	34	5	15	*3*
de Bever	5.3%	7	7.5%	8	5.0%	8	80%	8	32	4	35	*9*
de Bever with Trend	4.8%	3	6.3%	4	2.8%	4	40%	1	18	2	14	*1*
Energy Probe	5.3%	8	6.5%	5	3.0%	6	60%	1	56	8	28	*6*

Table 9

Actual and Forecast Niagara weather zone Environment Canada Degree Days ('out-of-sample'), 1990 to 2011

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 11*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*
Calendar Year	Actual	Naïve	10-yr MA	20-yr MA	20-yr Trend	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe
1990	3,307	3,693	3,693	3,703	3,685	3,705	3,695	3,633	3,651	3,679
1991	3,343	3,845	3,697	3,721	3,686	3,711	3,698	3,683	3,733	3,827
1992	3,759	3,307	3,635	3,697	3,607	3,697	3,652	3,619	3,585	3,623
1993	3,878	3,343	3,596	3,681	3,526	3,687	3,607	3,582	3,462	3,464
1994	3,780	3,759	3,600	3,677	3,562	3,692	3,627	3,640	3,568	3,568
1995	3,703	3,878	3,623	3,699	3,576	3,693	3,635	3,688	3,661	3,670
1996	3,786	3,780	3,630	3,701	3,598	3,701	3,650	3,697	3,693	3,731
1997	3,669	3,703	3,635	3,711	3,571	3,693	3,632	3,705	3,705	3,727
1998	2,980	3,786	3,653	3,704	3,615	3,704	3,659	3,708	3,754	3,736
1999	3,338	3,669	3,676	3,701	3,612	3,699	3,656	3,694	3,740	3,710
2000	3,596	2,980	3,605	3,649	3,500	3,670	3,585	3,624	3,639	3,539
2001	3,239	3,338	3,554	3,626	3,453	3,665	3,559	3,613	3,577	3,492
2002	3,415	3,596	3,583	3,609	3,486	3,659	3,573	3,617	3,580	3,586
2003	3,799	3,239	3,573	3,584	3,423	3,645	3,534	3,585	3,475	3,531
2004	3,632	3,415	3,538	3,569	3,405	3,631	3,518	3,575	3,468	3,589
2005	3,653	3,799	3,530	3,577	3,464	3,642	3,553	3,626	3,547	3,657
2006	3,163	3,632	3,516	3,573	3,494	3,639	3,566	3,636	3,558	3,633
2007	3,296	3,653	3,511	3,573	3,521	3,644	3,583	3,650	3,547	3,664
2008	3,480	3,163	3,448	3,551	3,437	3,619	3,528	3,607	3,511	3,484
2009	3,565	3,296	3,411	3,544	3,368	3,604	3,486	3,576	3,490	3,414
2010	3,344	3,480	3,461	3,533	3,374	3,586	3,480	3,564	3,483	3,464
2011	3,458	3,565	3,484	3,519	3,422	3,578	3,500	3,572	3,481	3,513
2013F		3,458	3,480	3,526	3,320	3,550	3,435	3,549	3,483	3,508

Table 10

The Niagara Degree Day: Out-of-sample forecast performance, all available years (1990 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.9%	9	11.0%	9	1.5%	2	59%	3	248	9	32	*8*
10-yr MA	6.0%	2	7.8%	2	2.4%	3	50%	1	80	5	13	*1*
20-yr MA	6.0%	1	8.3%	4	4.0%	7	59%	3	69	4	19	*4*
20-yr Trend	6.4%	6	7.8%	1	0.7%	1	41%	3	94	6	17	*3*
30-yr MA	6.3%	4	8.7%	6	4.9%	9	64%	8	40	1	28	*5*
50-50: 20-yr Trend & 30-yr MA	6.0%	3	8.0%	3	2.8%	5	50%	1	66	3	15	*2*
de Bever	6.4%	5	8.6%	5	4.0%	8	64%	8	47	2	28	*5*
de Bever with Trend	6.6%	8	8.8%	7	2.8%	4	59%	3	96	7	29	*7*
Energy Probe	6.6%	7	9.0%	8	3.3%	6	59%	3	109	8	32	*8*

Witnesses: H. Sayyan
M. Suarez

Table 11

The Niagara Degree Day: Out-of-sample forecast performance, recent ten year period (2002 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.0%	9	9.0%	9	0.5%	1	60%	2	203	9	30	*6*
10-yr MA	4.4%	1	5.3%	1	1.0%	3	50%	1	55	7	13	*1*
20-yr MA	4.7%	2	5.9%	2	2.6%	7	60%	2	27	1	14	*2*
20-yr Trend	4.9%	6	6.0%	4	0.9%	2	40%	2	51	6	20	*4*
30-yr MA	5.3%	7	7.0%	8	4.4%	9	70%	7	27	2	33	*8*
50-50: 20-yr Trend & 30-yr MA	4.8%	3	5.9%	3	1.8%	5	60%	2	36	4	17	*3*
de Bever	5.3%	8	6.9%	7	3.8%	8	70%	7	30	3	33	*8*
de Bever with Trend	4.9%	4	6.0%	5	1.3%	4	60%	2	40	5	20	*4*
Energy Probe	4.9%	5	6.8%	6	2.4%	6	70%	7	86	8	32	*7*

Table 12

The Niagara Degree Day: Out-of-sample forecast performance, recent five year period (2007 to 2011)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	6.9%	9	7.5%	9	0.3%	2	60%	1	200	9	30	*7*
10-yr MA	3.2%	3	3.9%	1	1.1%	3	60%	1	37	5	13	*1*
20-yr MA	3.7%	5	4.7%	5	3.5%	7	80%	4	20	1	22	*4*
20-yr Trend	3.1%	2	4.0%	2	0.0%	1	40%	1	62	7	13	*1*
30-yr MA	5.3%	8	6.2%	8	5.3%	9	100%	8	26	2	35	*9*
50-50: 20-yr Trend & 30-yr MA	3.5%	4	4.5%	4	2.6%	6	80%	4	42	6	24	*5*
de Bever	4.9%	7	6.1%	7	4.9%	8	100%	8	35	4	34	*8*
de Bever with Trend	3.1%	1	4.0%	3	2.3%	4	80%	4	28	3	15	*3*
Energy Probe	4.1%	6	5.6%	6	2.4%	5	80%	4	94	8	29	*6*

As detailed in Table 2, three methodologies show very close performance in the Central region: the 20-year Trend, the 10-year Moving Average, and the 50/50 Method. In terms of accuracy, the MAPE [1]results are comparable among the three methods. However, the RMSPE[2] is significantly lower for the 20-year Trend, indicating that the method produces fewer large errors. For symmetry, the 20-year trend's MPE[3] is by far the lowest at 0.3%, indicating that the methodology is the least likely to produce biased results (forecasts that are consistently high or low) although its POF[4] value is higher than the other two methodologies. Where stability is concerned, the 50/50 Method has a lower standard deviation than the other two methodologies, indicating that its forecasts are the least dispersed around an

[1] Mean Absolute Percent Error (MAPE), measures the absolute magnitude of the error relative to the actual value.
[2] Root Mean Percent Squared Error (RMPSE), similar to MAPE but squares the percentage error.
[3] Mean Percent Error (MPE), average percent error.
[4] Percent Over Forecast (POF), measures the number of over-forecasts. The closer the value to 50%, the more unbiased the method.

average. In summary, the 20-year Trend method performs well on the basis of accuracy and symmetry, while the 50/50 Method has better stability for all available years.

As shown in Table 6, the de Bever with Trend methodology has the highest overall rank followed by the 10-year Moving Average and the Energy Probe methods in the Eastern Region. In terms of accuracy, the de Bever with Trend is comparable to the 10-year Moving Average and better than the Energy Probe method. The de Bever with Trend also achieves the best symmetry. All three methods do not perform as well based on stability.

In Table 10, the 10-year Moving Average has the highest overall score, out-performing the 50/50 Method and the 20-year Trend in terms of accuracy. The 20-year Trend produced more symmetric forecasts as compared to the 10-year Moving Average. All three methods do not perform as well based on stability.

The Company believes that the evaluation template is a useful approach in systematically comparing the effectiveness of different methodologies using set criteria. As seen with this update, it is reasonable to expect that deviations could occur on the model recommendation from year to year. To assess the continued validity of the Board-approved 20-year Trend methodology for Central region, the de Bever with Trend method for the Eastern region, and the 10-year Moving Average for the Niagara zone over the longer term, the Company carried out the same evaluation process beyond the single 2013 test year for each year from 1990 to 2011. This allows for the use of all data available without arbitrarily selecting a set period. To establish a proven, reliable, consistent methodology over time, it is necessary to evaluate the persistence of that methodology in the long-run using all data available.

The validation of the degree day methodology was guided by the following question: if the evaluation template was consistently used to determine the forecast of degree days for each test year, what predominant methodology would the analysis have recommended? The Company applied the evaluation approach to each year over the last 22 years to assess the relative performance of forecasting methods that would have been recommended using all historical data available.

The Company generated out-of-sample forecasts, lagged two years, for each calendar year from 1990 to 2011. For instance, to determine the recommended methodology for a 1990 test year, out-of-sample forecasts for each method were calculated using data to 1988 for each of the weather zones. The resulting forecasts were then compared to the actual degree days for 1990 to measure each method on the basis of accuracy, symmetry, and stability. The methods were ranked for that test year according to how well the forecasts performed based on the test statistics from the evaluation process. The ranks in that test year would show, by order of preference, the methodologies that would have provided the most accurate, stable, and symmetric results. The same calculation was repeated for 1991, where out-of-sample forecasts would now use data up to 1989, etc.

Over the 22-year history, methodologies that consistently ranked high indicate ones that are best suited to each of the three regions over the long term. The results mostly showed very close scores for the top three methodologies. As a result, the Company considered methods that were ranked in the top three over the 22-year period.

Using this approach, the 20-year Trend methodology ranked in the top three methods in 20 out of the 22 years for the Central weather zone. Following the 20-year Trend methodology was the 50/50 method (19 out of 22 years). Comparatively, the 10-year Moving Average methodology was in the top three ranks in 14 out of the 22 years.

The results indicate that compared to the other methods evaluated the 20-year Trend showed the best consistent predictive ability. The fact that the 50/50 method is comprised by half of the 20-year Trend constitutes support for the relevance of this methodology for the Central region. As a result, the Company proposed in its original and update applications to apply the 20-year Trend to forecast degree days for the Central weather zone.

For the Eastern weather zone, the de Bever with Trend methodology had the best predictive ability, ranking in the top three for 17 out of the 22 years. The 10-year Moving Average had the second-best fit, ranking in the top three in 15 out of 22 years. By comparison, the Energy Probe method (which is the current Board-approved methodology that has been in place over the most recent 5 years) was ranked in the top three 10 out of 22 times.

The Company has proposed to apply the de Bever with Trend methodology to forecast degree days for the Eastern weather zone in both the original and updated 2013 evidence.

For the Niagara weather zone, the 10-year Moving Average methodology was tied with the de Bever method, both ranking in the top three for 13 out of 22 years each. The 30-year moving average was a close second at 12 out of 22 years. By comparison, the 50/50 method (which is the current Board-approved methodology that has been in place over the most recent 5 years) was ranked in the top three, 11 out of 20 years.

Whereas certain methods were more obvious choices in the Central and Eastern comparisons, results for the Niagara weather zone were not as conclusive and required additional consideration. The Company refined the selection to consider only the top-ranked methods over the 22 year period. Doing so resulted in the selection of the 10-year Moving Average as the most appropriate forecasting methodology for the Niagara region although it is recognized that the selected method is only slightly better than the alternatives.

The Company has proposed to apply the 10-year Moving Average to forecast degree days for the Niagara weather zone in both the original and updated 2013 evidence.

The evaluation process is a useful tool in systematically comparing the effectiveness of different methodologies using set criteria. The methodologies were validated beyond a single test year to establish a reliable, stable methodology over time. By extending the evaluation process to assess each year within a longer timeframe, the analysis has confirmed that certain methodologies naturally emerge as being best suited to forecast degree days for certain weather zones. These methods are the 20-year Trend, de Bever with Trend, and 10-year Moving Average for the Central, Eastern, and Niagara weather zones, respectively.

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 3: Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

Ref: Exhibit C2, Tab 3, Schedule 1

a) Please redo the analysis shown in Tables 1 through 12 with a two year ahead forecast. For example, the 2010 forecast would be based on actual data through 2008. Please include actual 2011 in the analysis.

b) Please provide the 2013 forecast for each methodology shown in Tables 1, 5 and 9 based on the two year ahead approach.

RESPONSE

a) All forecasts contained in the tables at Schedule 1 were generated using a two year-ahead period that include actual data to 2010. The updated 2013 forecast using 2011 actual data for proposed methodologies is provided in Table 1 at Exhibit C2, Tab 3, Schedule 2.

   For updates to Tables 1 through 12, please see the response to Energy Probe Interrogatory #1 part c) which provides updated forecasts two years ahead using actual data to 2011 (Exhibit I, Issue C3, Schedule 7.1).

b) Please see Energy Probe Interrogatory #1 part b) and c) at Exhibit I, Issue C3, Schedule 7.1.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

C - Operating Revenue
Issue 3: Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

Ref: Exhibit C2, Tab 3, Schedule 1

Does EGD assume that accuracy, symmetry and stability are all equally important criteria, or does EGD assume some other weighting of these three criteria? If so, please provide the weights and the rationale for the weights.

RESPONSE

The methodology proposed and approved as part of the 2007 application, and still in effect for the 2013 application, uses two measures for accuracy, two measures for symmetry, and one measure for stability. Each measure is weighted equally. As a result, stability has lesser weighting as compared to accuracy and symmetry.

The rationale for this approach was provided in the 2007 evidence here reproduced (EB-2006-0034, Exhibit C2, Tab 4, Schedule 1, page 7, paragraphs 17 and 18):

> "…the Company places half as much importance on Stability (compared to Accuracy and Symmetry) because methods that perform well in this regard are generally poorly equipped to respond to changing weather. Accuracy and symmetry are equally important. Neither ratepayers nor shareholders are well served by a methodology that produces relatively inaccurate results. Furthermore, since no method will be perfectly accurate, placing an importance on symmetry ensures that risks are not unevenly distributed amongst stakeholders. Meanwhile, stability is less important than accuracy and symmetry. Forecasts that are relatively more variable can result in greater rate shock. While rate shock is important, the consequences of inaccurate and/or biased forecasts are more significant."

Witnesses: H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

C - Operating Revenue
Issue 3: Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

Ref: Exhibit C2, Tab 3, Schedule 2

Do the forecast shown in Table 1 result from the two year ahead forecast that incorporates 2011 data? If not, please explain in detail how these forecasts have been derived and what data has been used to generate them. For example, does the 20 year trend methodology for the Central region include an updated regression equation based on 1992 through 2011 data?

RESPONSE

The forecasts in Table 1 result from the two year-ahead forecast that includes actual data up to and including 2011 for each weather zone. The 2013 forecasts were updated by re-estimating the models for the 20 Year trend methodology and the de Bever with Trend methodology with 2011 actual data for the Central and Eastern zones, respectively. For Niagara, the 10-year Moving Average was re-calculated to include actual degree days in the Niagara zone for the period from 2002-2011 to arrive at the 2013 forecast.

Witnesses: H. Sayyan
M. Suarez

VECC INTERROGATORY #1

INTERROGATORY

C- Operating Revenue
Issue 3: Is Enbridge's degree day forecast for each of the Company's delivery areas (EDA, CDA, and Niagara) appropriate?

Reference: Exhibit C1 Tab 3 Schedule 1 Degree Day Forecast

a) Please provide 2011 Actuals and 2012 Forecast, and update 2013 as required.

RESPONSE

Please see the table below which includes 2011 Actual, 2012 Board Approved and 2013 Proposed Environment Canada and Gas Supply Degree Day numbers for each of the Company's delivery areas (Central, Eastern and Niagara).

Environment Canada and Gas Supply Degree Days

Col. 1	*Col. 2*			*Col. 3*		
Calendar Year	**Environment Canada Degree Days**			**Gas Supply Degree Days**		
	Central	**Eastern**	**Niagara**	**Central**	**Eastern**	**Niagara**
2011 Actual	3,648	4,136	3,458	3,597	4,108	3,334
2012 Board Approved	3,557	4,382	3,468	3,532	4,343	3,418
2013 Proposed	3,512	4,334	3,480	3,481	4,297	3,420

Witnesses: H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Ref: Ex. C2 /Tab 2/ Sch 1 / para 27

What is the effect of the current, historically low gas prices on the average use model and its results? How significant is the price of gas relative to the other variables?

RESPONSE

Natural gas prices have a statistically significant but moderate impact on average use. Generally, low gas prices result in higher average use forecast as generated by the average use models.

Table 5 and Table 8, at Exhibit C2, Tab 2, Schedule 1, show the regression results for Rate 1 and Rate 6 average use models, respectively. The coefficients of the explanatory variables in the long run average use equations can be interpreted as the elasticity and show the relationship between the explanatory variables and average use demand for each region in the Company's franchise area. The magnitude of the coefficient determines the extent of the explanatory variable's impact on the average use forecast.

Taking the Rate 1 Central region model in the Central weather zone as an example, the coefficient of real gas price variable (0.06) is interpreted to show that a 1% increase in real gas price would lead to a 0.06% decline in the Central region's average use, assuming all other variables in the model are held constant.

Similarly the coefficient of central degree days 0.72 shows that 1% increase in the Central degree day would cause 0.72% increase in the region's average use.

In both Rate 1 and Rate 6 models, it is evident that the degree day variable has the greatest impact on the average use forecast. Following the degree day impact are the vintage variable for Rate 1 models and economic variables in the Rate 6 models.

Witnesses: H. Sayyan
M. Suarez

BOMA INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Ref: Exhibit C2, Tab 2, Schedule 1, Page 20 of 22.

With respect to the statement "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", please provide any studies which support this assumption. Has any study been done comparing natural improvements in thermal improvements, i.e. those undertaken by the homeowners without any financial assistance from utilities or governments to the level of savings achieved under a utility or governmental conservation/efficiency program?

RESPONSE

The statement referred to above acknowledges that because of the Energy Efficiency Act of 1992, energy efficiency standards put in place for various products and appliances have had a more widespread and rapid impact on reducing energy consumption by raising the minimum required level of efficiency for gas equipment than what naturally occurring market adoption for thermal improvements would have achieved.

The Company is not aware of any specific studies that compare the level of savings between homeowner-initiated or naturally occurring improvements and those promoted by utility conservations programs.

Witnesses: H. Sayyan
M. Suarez

CCC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Ref: C5/T2/S3/p. 1

Please provide the forecast General Service Average Uses for the years 2005-2011.

RESPONSE

Please see the following Table for the forecast General Service Average Uses for the years 2005 - 2011.

GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		2005**	2006 Budget	2007 Budget	2008 Budget	2009 Budget	2010 Budget	2011 Budget
Residential		2,982	2,796	2,652	2,624	2,627	2,593	2,579
	Change		(186)	(144)	(28)	2	(34)	(14)
	% Change		-6.24%	-5.14%	-1.06%	0.09%	-1.29%	-0.53%
Apartment		79,412	83,264	78,295	118,486	138,206	147,587	144,228
	Change		3,852	(4,970)	40,191	19,720	9,382	(3,360)
	% Change		4.85%	-5.97%	51.33%	16.64%	6.79%	-2.28%
Commercial		17,284	16,899	16,438	17,348	18,593	18,400	18,674
	Change		(385)	(461)	910	1,245	(193)	274
	% Change		-2.23%	-2.73%	5.54%	7.18%	-1.04%	1.49%
Industrial		57,234	53,117	52,158	66,052	115,388	100,741	101,273
	Change		(4,117)	(958)	13,894	49,336	(14,647)	532
	% Change		-7.19%	-1.80%	26.64%	74.69%	-12.69%	0.53%

* All historical average uses are on a calendar-year basis and have been normalized to the 2013 Budget degree days.
** 2005 Budget average uses were developed based upon fiscal-year basis (October to September). As such the forecast normalized average uses cannot be provided. 2005 actual normalized average uses are presented instead.

Witnesses: R. Lei
S. Qian

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Ref: Exhibit C1, Tab 3, Schedule 1

a) Please confirm that Figures 1 & 2 & 3 include actual 2011 data. If this cannot be confirmed, please provide revised figures that include actual 2011 data.

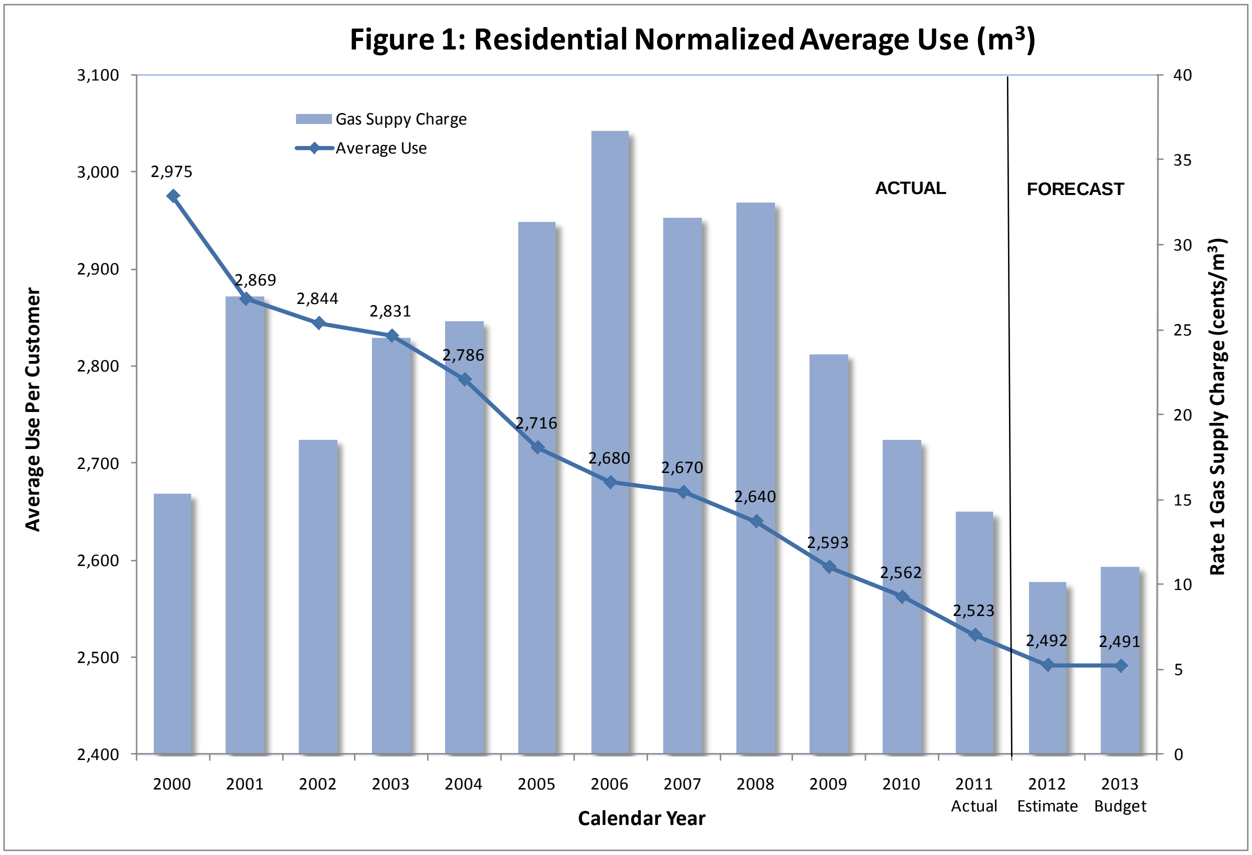
b) What is the basis for the statement on page 6 that the mass migration from rates 100 and 145 to rate 6 has come to an end?

RESPONSE

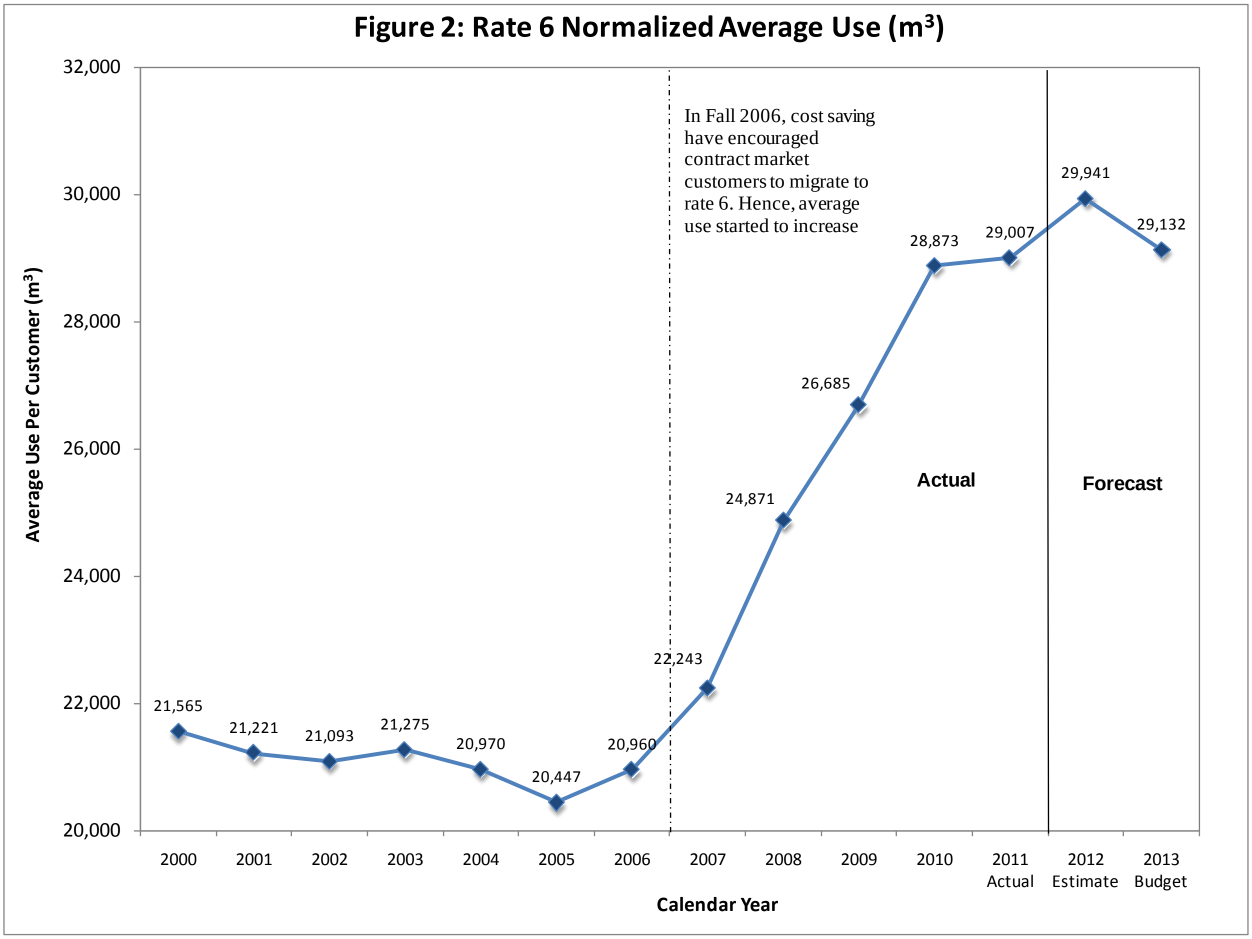
a) At Exhibit C1, Tab 3, Schedule 1, Figures 1, 2, and 3 did not include actual 2011 data. Figure 1 on the following page shows the normalized average use per customer for Rate 1, with revised figures that include 2011 actual data and updated 2013 Budget. Figure 2 shows the normalized average use per customer for Rate 6, with revised figures that include 2011 actual data and updated 2013 Budget. These updated Figures are consistent with the updated evidence at Exhibit C5, Tab 2, Schedule 3, filed on June 1, 2012.

Figure 3 shows the historical actual contract market unlocks between 2006 and 2011, and the projection for 2012 and 2013.

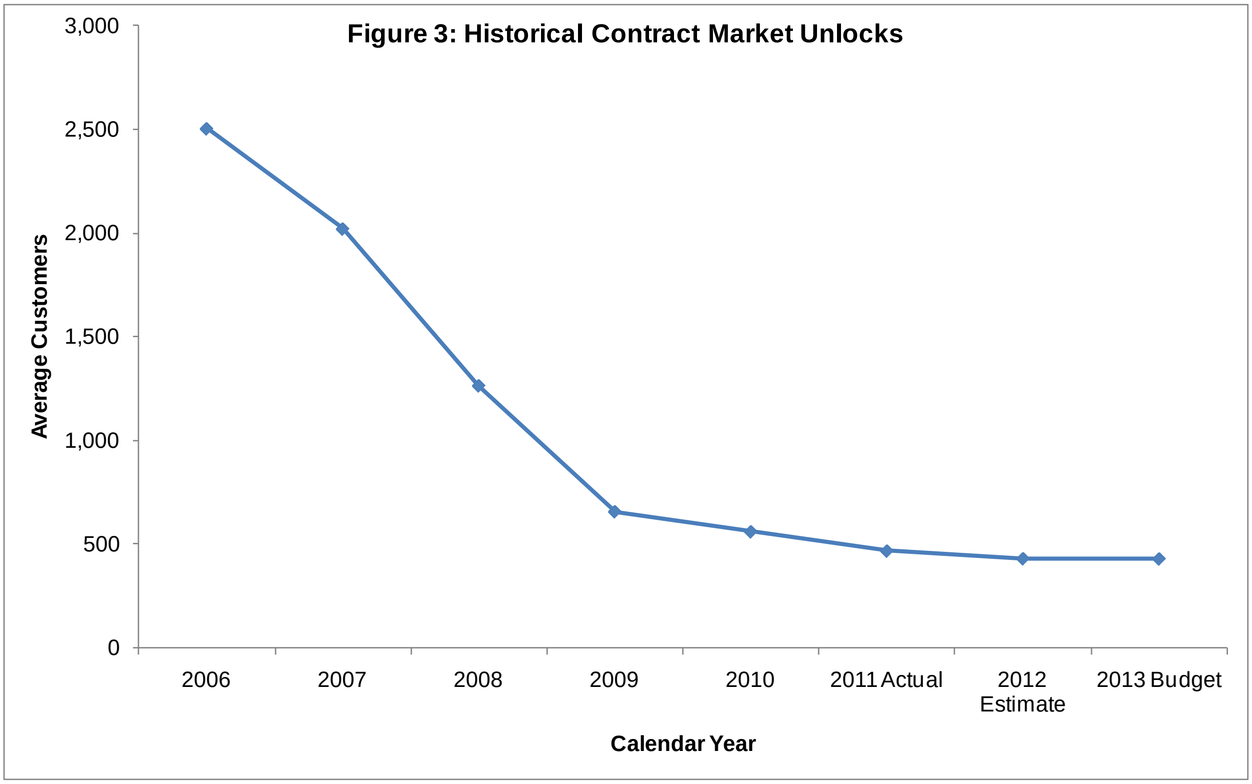
Witnesses: R. Lei
S. Qian



Witnesses: R. Lei
S. Qian



Witnesses: R. Lei
S. Qian



b) As illustrated in the above Figure 3, approximately 2,000 contract market customers have migrated to general service over the period of 2006 to 2011. Rate design changes required Rates 100 and 145 to pay contract demand charges, effective April 1, 2007. The majority of these customers have already migrated from Rate 100 and above, to Rate 6 from 2006 to 2011. EGD anticipate that the migration between general service and contract market has stabilized and the Company does not expect that any contract market customers will migrate to general service between 2012 and 2013.

Witnesses: R. Lei
S. Qian

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Ref: Exhibit C2, Tab 2, Schedule 1

a) Please provide the actual volumes and number of customers for each revenue class in Rate 1 (10, 20, 50, 60, 61) for 2011. Have the proportion of volumes between the classes changed significantly over the last 5 years? If yes, please provide details of any trends.

b) Please provide the actual volumes and number of customers for each revenue class in Rate 6 (12, 48, 73, 79, 83, 86, 90) for 2011. Have the proportion of volumes between the classes changed significantly over the last 5 years? If yes, please provide details of any trends.

RESPONSE

a) Table 1 shows the actual volumes and average number of customers for each revenue class in Rate 1 for 2011. The proportion of volumes between revenue classes have not changed significantly over the last 5 years as approximately 87% of volumes in Rate 1 belong to revenue class 20.

Witnesses: R. Lei
S. Qian

Table 1
Summary of 2011 Actual Rate 1 Volumes and Customers

Revenue Class Group	Un-Normalized Volume (10^6m^3)	Customer (Average)
10	299.3	140,190
20	4,109.9	1,584,490
50	274.6	60,062
60	2.4	4,618
61	13.7	13,218
Total	4,699.9	1,802,578

b) Table 2 shows the actual volumes and average number of customers for each revenue class in Rate 6 for 2011. The proportion of volumes between revenue classes in Rate 6 have moderately changed over the last 5 years. The change is largely attributable to the rate switching from contract market customers to general service, which began in fall of 2006. As stated on page 6 of Exhibit C1, Tab 3, Schedule 1, rate design changes to include contract demand charges on Rate 100 and Rate 145 customers have prompted much of this rate migration.

Table 3 provides detail of the volumes distribution on Rate 6 by revenue class from 2007 to 2011. As a result of the rate migration, the total percentage of Rate 6 volumes in revenue classes 12, 48 and 73 has decreased from 97% in 2007 to 90% in 2011, while the remaining revenue classes have increased from 3% in 2007 to 10% in 2011.

Witnesses: R. Lei
S. Qian

Table 2
Summary of 2011 Actual Rate 6 Volumes and Customers

Revenue Class Group	Un-Normalized Volume (10^6m^3)	Customer (Average)
12	751.4	6,190
48	2,839.1	139,204
73	665.6	6,025
79	73.2	4,538
83	8.5	90
86	375.4	1,148
90	6.8	128
Total	4,720.0	157,323

Table 3
Summary of Rate 6 Volumes Distribution

Revenue Class Group	2007	2008	2009	2010	2011
12	18.1%	21.5%	20.2%	16.1%	15.9%
48	68.3%	64.2%	62.2%	59.1%	60.1%
73	10.6%	11.7%	12.8%	14.1%	14.1%
79	1.8%	1.5%	1.4%	1.7%	1.6%
83	0.2%	0.2%	0.2%	0.2%	0.2%
86	0.8%	0.7%	3.0%	8.6%	8.0%
90	0.2%	0.2%	0.2%	0.2%	0.1%
12, 48 & 73 Total	97.0%	97.4%	95.2%	89.3%	90.1%
79, 83, 86 & 90 Total	3.0%	2.6%	4.8%	10.7%	9.9%

Witnesses: R. Lei
S. Qian

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Ref: Exhibit C2, Tab 2, Schedule 1, Updated

a) Please explain why the time variable, with a T-stat of -0.91 was left in the Niagara Weather Zone equation shown on page 11.

b) Please provide the regression statistics for the other five long run equations shown on pages 10 and 11 if the time variable is included in the equations.

RESPONSE

a) To update the average use forecast, the average use models are subjected to a battery of tests to ensure that they are statistically valid and that the forecasts produced by the models are highly accurate.

   Part of those tests includes a specification test to ensure that the correct explanatory variables are chosen for each regression equation. The Company considered whether the variables are essential to the regression on the basis of expected driver relationships, whether the sign on the coefficients and the size of the coefficients are significant, and whether the addition of certain variables improves the test results and accuracy of the model.

   The addition of the time variable to the Niagara Weather Zone equation significantly improved the t-test result of the other explanatory variables in the model, as well as the model's diagnostic test results. It is for this reason that the Company chose to leave the time variable in the model.

b) The results of the updated forecast with the inclusion of the time variable in the other five residential long run equations are provided in the following tables.

Witnesses: H. Sayyan
M. Suarez

Updated results show that when the time variable was included in the other five long run equations, the results were worse than when the variable was excluded from the models. For instance, when the time variable is added to the Central Weather Zone equation, it makes the other explanatory variable (real gas price) insignificant in both the long run and short run equations. The Adjusted R-squared of the short run equation is also lowered through the inclusion of the time variable in the model. It is for these reasons that the Company decided not to include the time variable in these equations.

TABLE 5 - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Metro Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	2.49	6.41	0.00
LOG(CDD)	0.72	14.89	0.00
LOG(REALCRCRPG)	-0.02	-0.98	0.34
LOG(MET20VINT)	0.62	4.42	0.00
DUM2008	-0.06	-4.24	0.00
LOG(TIME)	0.00	0.10	0.92
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.02		
F-statistic	255.08		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-0.32	0.75
DLOG(CDD)	0.76	25.83	0.00
DLOG(MET20VINT)	0.69	1.71	0.10
ECM_MET20(-1)	-0.32	-1.75	0.09
R-squared	0.97		
Adjusted R-squared	0.97		
S.E. of regression	0.01		
F-statistic	253.61		0.00

Western Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.43	1.90	0.07
LOG(CDD)	0.71	22.60	0.00
LOG(REALCRCRPG)	-0.04	-2.21	0.04
LOG(WES20VINT)	0.34	6.93	0.00
LOG(CENTEMP)	0.12	1.47	0.16
DUM2008	-0.04	-4.54	0.00
LOG(TIME)	0.02	3.23	0.00
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	479.68		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	-2.19	0.04
DLOG(CDD)	0.72	31.97	0.00
DLOG(REALCRCRPG)	-0.07	-3.61	0.00
DUM2008	-0.02	-2.65	0.01
ECM_WES20(-1)	-0.69	-3.05	0.01
R-squared	0.98		
Adjusted R-squared	0.98		
S.E. of regression	0.01		
F-statistic	283.13		0.00

Central Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.82	0.93	0.36
LOG(CDD)	0.71	17.16	0.00
LOG(REALCRCRPG)	-0.03	-1.12	0.28
LOG(CEN20VINT)	0.38	8.00	0.00
LOG(CENTEMP)	0.19	2.02	0.06
DUM2008	-0.05	-4.24	0.00
LOG(TIME)	0.02	1.89	0.07
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	330.09		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.80	0.43
DLOG(CDD)	0.71	21.03	0.00
DLOG(REALCRCRPG)	-0.03	-1.12	0.27
DLOG(CEN20VINT)	0.36	2.34	0.03
DUM2008	-0.02	-1.91	0.07
ECM_CEN20(-1)	-0.85	-3.14	0.01
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.01		
F-statistic	105.89		0.00

Witnesses: H. Sayyan
M. Suarez

TABLE 5 CONTINUED - RATE 1 REVENUE CLASS 20 REGRESSION EQUATIONS

Northern Region - Central Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.33	1.74	0.10
LOG(CDD)	0.70	21.20	0.00
LOG(REALCRCRPG)	-0.05	-1.97	0.06
LOG(NOR20VINT)	0.33	8.63	0.00
LOG(CENTEMP)	0.15	1.81	0.09
DUM2009	-0.04	-3.42	0.00
LOG(TIME)	0.02	2.92	0.01
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	617.74		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	0.00	0.64	0.53
DLOG(CDD)	0.70	21.83	0.00
DLOG(REALCRCRPG)	-0.02	-0.87	0.39
DLOG(NOR20VINT)	0.33	2.66	0.01
ECM_NOR20(-1)	-0.87	-2.78	0.01
R-squared	0.96		
Adjusted R-squared	0.95		
S.E. of regression	0.01		
F-statistic	130.75		0.00

Eastern Weather Zone

Long Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	1.38	3.64	0.00
LOG(EDD)	0.81	17.55	0.00
LOG(REALERCRPG)	-0.04	-2.19	0.04
LOG(ERC20VINT)	0.24	6.39	0.00
DUM2008	-0.06	-5.50	0.00
LOG(TIME)	0.00	-0.03	0.98
R-squared	0.99		
Adjusted R-squared	0.99		
S.E. of regression	0.01		
F-statistic	408.43		0.00

Short Run Equation

Variable	Coefficient	t-Statistic	p-Value
C	-0.01	-2.77	0.01
DLOG(EDD)	0.79	23.93	0.00
DLOG(REALERCRPG)	-0.06	-2.18	0.04
DUM2008	-0.01	-1.82	0.08
ECM_ERC20(-1)	-0.68	-2.97	0.01
R-squared	0.97		
Adjusted R-squared	0.96		
S.E. of regression	0.01		
F-statistic	154.66		0.00

Witnesses: H. Sayyan
M. Suarez

FRPO INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Reference: C1, Tab 3, Schedule 1, page 6-7

Preamble: At the end of paragraph 6, EGD states: It is expected that the mass rate migration has come to an end, and, therefore, that the Rate 6 average use per customer will decrease slightly in 2013 compared to 2012.

At the end of paragraph 7, EGD states: Therefore, the impact of rate migration is layered onto the regression model's average use forecast at a later stage.

1. Please update the figure for 2011 Actuals including any adjustments to forecast.

2. Please provide the evidence or analysis upon which EGD is relying to project a decrease in Normalized Average Use.

3. What level of migration is layered on for the resulting 2013 forecast?

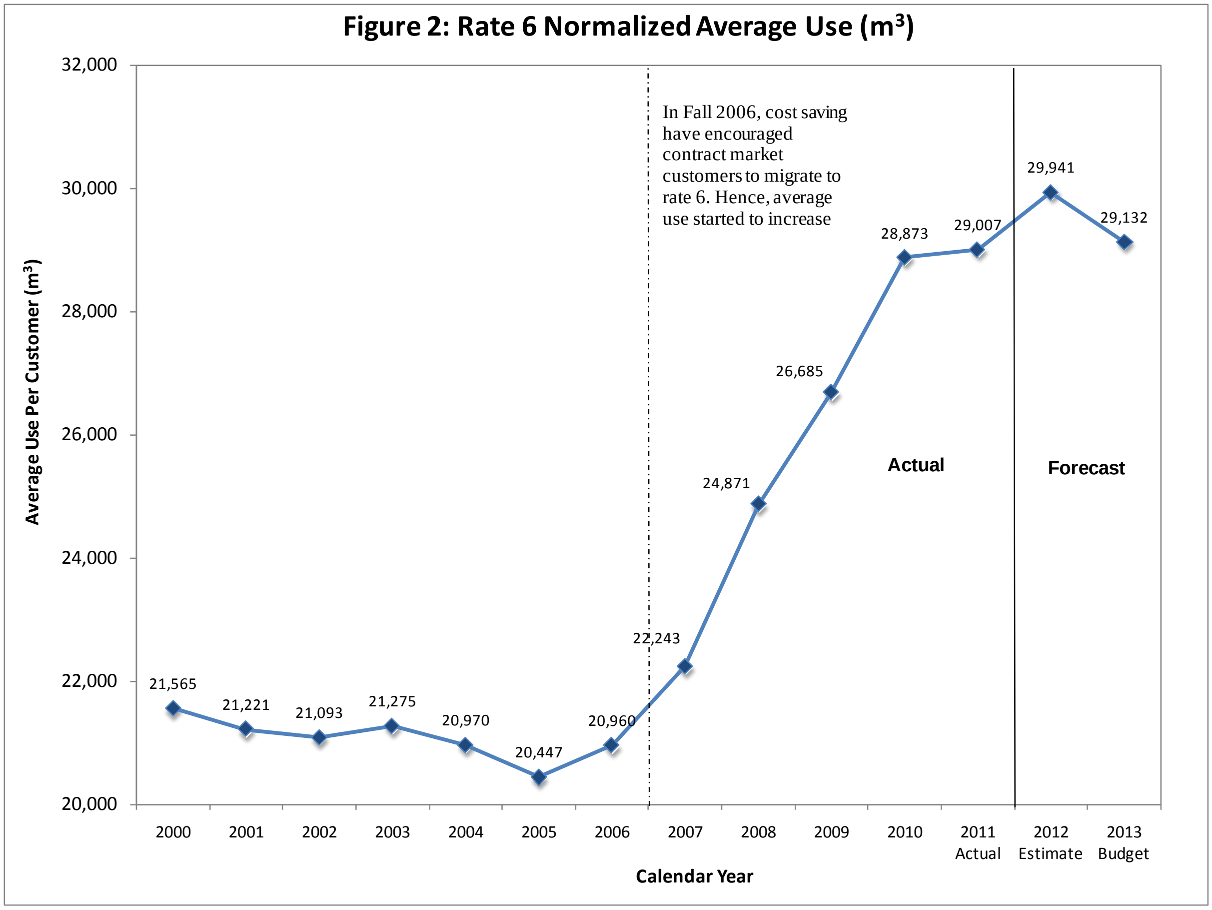
4. What is the revenue requirement impact if 2013 values were projected to remain constant at 2012 estimated levels?

5. What is the revenue requirement impact if 2013 values were projected assuming a layering of migration realized in the 2010-2011 actuals?

RESPONSE

1. Figure 2, at Exhibit C1, Tab 3, Schedule 1, is updated below and includes 2011 actual data and 2013 updated Budget. These numbers are consistent with the table as shown at Exhibit C5, Tab 2, Schedule 3, page 3 in the updated evidence.

Witnesses: R. Lei
S. Qian
H. Suyyan
M. Suarez



2. The normalized average use forecast for Rate 6, as shown at Exhibit C5, Tab 2, Schedule 3, page 2, relies on the results of average use forecasting models as presented at Exhibit C2, Tab 2, Schedule 1. The models, which are developed at the revenue class and regional levels rely on historical average use and driver variable data. They are subjected to a battery of specification tests to ensure statistical validity. In addition, forecast accuracy is measured to ensure that the models show a high level of predictive ability.

3. EGD does not anticipate any significant migration from contract market customers to Rate 6 between 2012 and 2013.

4. The 2013 test year volumes would increase in Rate 6 if 2013 normalized average uses remain constant at 2012 Estimate levels. The volume would increase by 128.9 $10^6 m^3$. This volumetric change could lead to other adjustments to be undertaken in gas cost, transportation and storage departments. Curtailment

Witnesses: R. Lei
S. Qian
H. Suyyan
M. Suarez

volumes, commodity purchases, unaccounted for gas, storage levels and transportation would all be impacted. Assuming that the volume increases would be the sole driver of a change in revenue deficiency, it would result in a decrease in the revenue deficiency of approximately $4.2 million.

5. As stated in the response to question 4 above, and assuming that the volume changes would be the sole driver that impacts the revenue requirement, a layering of migration that was realized in the 2010-2011 actual would result in a decrease in the revenue deficiency of approximately $1.4 million.

Witnesses: R. Lei
S. Qian
H. Suyyan
M. Suarez

VECC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Reference: Exhibit C1 Tab 3 Schedule 1

a) Please confirm that Figures 1 & 2 & 3 include actual 2011 data. If this cannot be confirmed, please provide revised figures that include actual 2011 data.

b) With regard to Figure 2, although EGD states (para 11) that “It is expected that the mass rate migration has come to an end, and, therefore, that the Rate 6 average use per customer will decrease slightly in 2013 compared to 2012”, does EGD agree that there is a turning point in Rate 6 NAC and accordingly the forecast is subject to more error?

c) Figure 1 shows the following NACs: 2010-29,030 m3; 2011-29780 m3 (is this the actual? Please see above); 2012- 30,025 m3; 2013-29,988 m3. Please provide the error statistics for the 4 year actual/forecast period 2010 -2013, and compare these to the overall error statistics in Exhibit C2 Tab 2 S1 Tables 1, Table 3 and Table 9.

d) Assume that the turning point continues in 2013 and use a rule of thumb that the delta 2012-2013 is 50% of the delta 2011-2012 to calculate the 2013 NAC.

RESPONSE

a) Not confirmed. For the requested 2011 actual data please refer to the response to Energy Probe Interrogatory, at Exhibit I, Issue C4, Schedule 7.1, part a).

b) EGD is not of the view that the average use forecast is subject to more error. The average use models are Company-developed regression models. As shown in Exhibit C5, Tab 2, Schedule 5, as updated on June 1, 2012, the average in-sample forecast error during the period 2001 - 2011 for Rate 6 regression models is less than 1.6%. The regression models have been an excellent predictor of general service normalized average use. In addition, the majority of the contract market

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

customers whose bills were lower on Rate 6 have already migrated to Rate 6. Thus, it is expected that Rate 6 normalized average uses are stabilizing as compared to the period of 2006 to 2010. EGD does not anticipate any significant migration from contract market rate classes to Rate 6 between 2012 and 2013.

c) The normalized average use forecast was updated to account for the latest actual data from 2011 as part of the evidence submitted on June 1, 2012. The average use models were re-estimated and updated to reflect the latest data, results of which were updated at Exhibit C2, Tab 2, Schedule 1, and Exhibit C5, Tab 2, Schedule 3. Evidence at Exhibit C1, Tab 3, Schedule 1, was not part of the update, but values in Figure 1 and Figure 2 would have reflected those shown at Exhibit C5, Tab 2, Schedule 3, pages 1 and 2. Figures 1, 2, and 3 have been updated as part of an interrogatory response. Please see part a) of this interrogatory for the reference. This response will refer to the updated evidence specifically for Rate 6 average uses.

Below is a summary of the normalized actual and forecast average uses for 2010 - 2013. Values in Column 2 refer to the updated average use for Rate 6 as shown in Exhibit C5, Tab 2, Schedule 3, page 2. Values in Column 3 refer to updated evidence as shown in Exhibit C2, Tab 2, Schedule 1, Table 3.

Rate 6 Normalized Average Use Per Customer (m3)

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
			Board-Approved	
Calendar Year	**C5 T2 S3 page 2**	**C2 T2 S1 Table 3, col 2**	**C2 T2 S1 Table 3, col 3**	**% Variance** 100*((Col.3-Col.4)/Col.3)
2010 Actual	28,873	29,106	27,949	4.1%
2011 Actual	29,007	29,471	28,029	5.1%
2012 Board-Approved	29,941			
2013 Proposed	29,132			

The difference in the normalized average uses between Column 2 and Column 3 is due to the difference in the degree days used to normalize the values. All average uses in Column 2 have been normalized to the 2013 Forecast degree days while those in Column 3 are normalized to yearly Board approved degree days. For example, the 2011 Actual average use in Column 2 has been normalized to the 2013 Forecast degree days, and the 2011 Actual average use in Column 3 has been normalized to the 2011 Board approved degree days. Board-approved average uses in Column 4 are normalized according to the degree days approved in each year.

To measure the forecast error between actual average uses and Board-approved for previous years, it is appropriate to compare the forecast and actual values in Column 3 and Column 4 which have been normalized on the same basis. Column 5 is the forecast error which represents the percentage variance of the normalized average use per customer as shown in column 5 of Table 3, at Exhibit C2, Tab 2, Schedule 1, page 7.

For forecasting purposes, the Company employs a Board-approved average use forecasting methodology; please see Exhibit C2, Tab 2, Schedule 1. Average use models are developed at the revenue class and regional levels and subjected to a battery of specification tests to ensure statistical validity. The results of those specification tests are shown in Table 9, at Exhibit C2, Tab 2, Schedule 1, page 18.

Having confirmed the statistical validity of the models used, the Company tests the predictive ability of the average use models developed using the forecasts errors reproduced here from Table 1, at Exhibit C2, Tab 2, Schedule 1, page 5.

Rate 6 Forecast Errors

Col 1.	*Col 2.*
Forecast Error Method	**Rate 6**
In-Sample % Variance (2 Years)	-0.53%
In-Sample RMSPE (2 Years)	0.80%
Out-of-Sample % Variance (2 Years)	-2.48%
Out-of-Sample RMSPE (2 Years)	2.67%

The forecast errors are calculated to measure the forecast accuracy of regression models that are used to forecast 2013 average use see Table 8, Exhibit C2, Tab 2, Schedule 1, page 15. The models are run to generate estimates for the entire sample, 1985 - 2011 to measure in-sample accuracy and for the period of 1985-2009 to measure out-of sample accuracy. Forecasts of average use are produced under both approaches and compared against actual average use from 2010 to 2011 using % Variance and RMSPE statistics. Both in-sample and out-of sample accuracy statistics in the table show Rate 6 average use forecasts that produced by the models are highly accurate.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

d) The volumes that originate from the migration of contract market customers to Rate 6 during the period of 2011 and 2012 have been incorporated into the development of 2013 normalized Rate 6 average use. Hypothetically assuming that 50% of the volumes that migrated from the contract market between 2011 - 2012 are used to re-calculate the 2013 normalized average use, the new Rate 6 normalized average use would increase by approximately 0.3%. Detail calculations are shown below.

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10
	C3_T2_S1	C3_T2_S1	(Col.1 / Col.2) C5_T2_S3	2011-2012	2011-2012			(Col.1 + Col.6)	(Col.2 + Col.7)	(Col.8 /Col.9)
Rate 6	Volumes (m^3)	Unlocks	Average Use (m^3)	Volumes - Migration from Contract Market (m^3)	Unlocks - Migration from Contract	50% of Volumes (Col.4)	50% of unlocks (Col.5)	New Volumes (m^3)	New Unlocks	New Average Use (m^3)
Jan	733,189,580	160,358	4,572.2	7,292,848	63	3,646,424	32	736,836,004	160,390	4,594.0
Feb	778,291,020	160,529	4,848.3	6,785,743	55	3,392,872	28	781,683,892	160,557	4,868.6
Mar	708,056,459	160,553	4,410.1	4,842,927	49	2,421,464	25	710,477,923	160,578	4,424.5
Apr	462,900,692	159,842	2,896.0	4,205,982	48	2,102,991	24	465,003,683	159,866	2,908.7
May	294,542,339	158,999	1,852.5	3,104,138	45	1,552,069	23	296,094,408	159,022	1,862.0
Jun	155,881,501	157,983	986.7	1,148,579	41	574,290	21	156,455,791	158,004	990.2
Jul	111,234,807	157,321	707.1	656,799	30	328,400	15	111,563,206	157,336	709.1
Aug	102,752,760	156,565	656.3	581,901	25	290,951	13	103,043,710	156,578	658.1
Sep	120,140,647	155,907	770.6	523,850	25	261,925	13	120,402,572	155,920	772.2
Oct	169,983,420	156,503	1,086.1	634,606	22	317,303	11	170,300,723	156,514	1,088.1
Nov	346,387,773	157,840	2,194.6	1,147,952	21	573,976	11	346,961,749	157,851	2,198.0
Dec	662,343,213	159,523	4,152.0	1,430,555	15	715,278	8	663,058,490	159,531	4,156.3
Total	**4,645,704,211**		**29,132.4**	**32,355,880**		**16,177,940**		**4,661,882,151**		**29,229.8**
								Change from original average use		0.3%

Witnesses: R. Lei
S. Qian
H. Sayyan
M. Suarez

VECC INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 4: Is the Average Use forecast appropriate?

Reference: Exhibit C1 Tab 3 Schedule 1 Table 6

a) Please provide a summary of Power Market Volumes from 2007-2013F.

b) Are these volumes included in the 2011A and 2012E numbers in Table 6?

c) What is the change in Power Market Volumes in 2013 attributed to?

RESPONSE

a) The Company's power market customers consist of both unbundled customers and bundled rate classes.

Unbundled customers use the Company's distribution network for the transportation of natural gas and do not bill distribution volumes volumetrically. The unbundled rate classes incur monthly contract demand volumes and generate fixed contract demand revenues. Table 1 presents a summary of the contract demand volumes for these customers.

Table 1
Summary of Unbundled Customers Contract Demand Volumes
(Volumes in $10^6 m^3$)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Budget
Rate 125	11.8	38.9	73.1	81.0	79.3	106.2	119.2

Witnesses: R. Lei
S. Qian

The Company also has power market customers in bundled rate classes. Table 2 presents a summary of the distribution volumes for these customers.

Table 2
Summary of Bundled Power Market Customers Distribution Volumes
(Volumes in 10^6m^3)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Budget
Power Market	465.5	354.4	204.7	235.7	248.3	239.9	246.6

b) The contract demand volumes for unbundled customers in power market were included in Table 2 at Exhibit C1, Tab 3, Schedule 1. The power market volumes for bundled customers were included in the 2011 Historical and 2012 numbers in Table 6, at Exhibit C1, Tab 3, Schedule 1. The following Table 3 provides an updated version for Table 6, incorporating 2011 Actual and 2012 Estimate.

Witnesses: R. Lei
S. Qian

Table 3 - Comparison of Contract Market Volumes
2012 Estimate and 2011 Actual
(10^6m^3)

	Col. 1	Col. 2	Col. 3
	2012 Bridge Year Estimate	2011 Actual	2012 Estimate Over (Under) 2011 Actual (1-2)
Contract Market Total Gas Sales and Transportation Volumes	1,943.4	2,082.5	(139.1)
Major Variance Factors:			
Weather Normalization, Exhibit C, Tab 4, Schedule 3, Page 4, Col. 4, Item No. 4			(4.8)
Lost customers			(1.2)
Transfer gains - migration of customers from general service rate 6 to contract rate 110			0.9
Transfer losses - net migration of customers from contract rates to general service rate 6			(32.4)
Wholesale customer			(6.5)
Refined Petroleum Industry			(25.4)
Impact of price spread between Hydro and Gas on Distributed Energy customers			(20.9)
Non-Metallic Mineral Products Industry			(7.4)
Pulp & Paper Industry			(12.4)
Chemical and Chemical Products Industry			(4.6)
Primary Metal & Machinery Industry			(10.1)
Transportation Equipment Industry			(5.9)
Others change in usage (e.g. change in production process, etc.)			(8.4)
Total Major Variance Factors:			**(139.1)**

c) The increase of 13.0 10^6m^3 of contract demand volumes between 2012 and 2013 in Table 1 is mainly attributed to one new unbundled customer added in mid-year 2012.

Witnesses: R. Lei
S. Qian

BOARD STAFF INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / para 1

When did the Unaccounted For Variance Account ("UAFVA") first get approval from the Board? What were the reasons the Company requested the account? Has the rationale or need for this account changed over time? Please explain.

RESPONSE

The UAFVA was first approved by the Board in 2002 (RP-2001-0032). The Company sought a variance account to address the high variability between the Board approved level UAF and the actual UAF. As noted in RP-2001-0032, Exhibit A, Tab 12, Schedule 5, the reason for the variance was the high volatility in UAF itself which contributed to variability in gas costs. The confidence interval at 95% was calculated from a lower-bound of 31,968 10^3m^3 to an upper-bound of 144, 976 10^3m^3 using data from 1993 to 2001.

Using the actual data at Exhibit D3, Tab 4, Schedule 1, page 6, Table 3, where actual fiscal data were converted to calendar data for comparability, the confidence interval at 95% for the period 1993 to 2001 is from 32,605 10^3m^3 to 145,922 10^3m^3. Extending this analysis to include actual UAF up to 2011, the comparative range has increased so that there is a 95% probability that UAF will fall between (19,814) 10^3m^3 to 148,380 10^3m^3.

Since the establishment of the UAFVA account, UAF has become even more volatile. The period from 2002 to 2011 has a higher variability than the period from 1993 to 2001. As a result, the need and rationale for the UAFVA are reinforced.

Witnesses: K. Culbert
H. Sayyan
R. Small
M. Suarez

BOARD STAFF INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / page 5 / Table 2

With respect to Table 2, please expand the table to include the figures for 2012 and 2013 and all Actual and Board-approved amounts (dollars and volume) since the account was first established. Please include the amounts included in rates, the UAFVA variance account amounts, and the disposition amounts.

RESPONSE

Table 2 has been expanded to include actual UAF volumes, Board-Approved UAF volumes, corresponding UAF amounts in rates ($), and the UAF variance and disposition amounts since the UAFVA was first established in 2002.

Table 2
UAF Actuals vs Board Approved -- Modified for Interrogatory Response

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*
Calendar Year	**UAF**	**UAF - Board Approved (10^3m^3)**	**UAF Amounts in Rates ($M)**	**UAFVA Balance Approved & Cleared ($M)**
2002*	9,284	65,031	14.7	(15.9)
2003*	21,412	54,862	15.5	(1.5)
2004*	-22,406	56,603	17.7	(40.0)
2005*	14,815	31,302	23.1	3.9
2006	10,274	39,162	12.3	(11.7)
2007	83,823	39,444	15.0	6.1
2008	44,424	39,444	12.8	0.6
2009	110,917	31,841	12.3	9.6
2010	72,104	37,795	9.0	8.7
2011**	73,355	64,211	13.2	8.5
2012		68,925	13.6	
2013***		73,092	11.7	

* Board-approved amounts from 2002-2005 represent UAF for a fiscal year (12 months ending September 30); Actual UAF for the same period is shown on a calendar year basis (12 months ending December 31).
** 2011 UAFVA as proposed in the ESM proceeding, EB-2012-0055. All other UAFVA balances as provided in EB-2011-0008, Ex I T1 S10.
*** 2013 UAF Forecast

Witnesses: I. Chan
H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #3

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / page 5 / Table 2

With respect to Table 2, please explain why the 2006 actual UAF is a relatively low amount.

RESPONSE

Unaccounted for Gas (UAF) is the difference between gas that is delivered into the distribution system (as billed by TCPL and Union Gas) and metered gas consumption of the Company's 1.96 million customers. UAF arises from meter differences (affected by temperature and pressure fluctuations), operational or external factors such as line leakage, unmetered uses, and third party damages. For a description of the Company's efforts to measure, control and manage the amount of UAF, please see Exhibit D2, Tab 6, Schedule 1.

As the name implies, UAF is the volumetric discrepancy that cannot be accounted for, hence the reasons for these volumetric losses are not identifiable. The fact that actual UAF in 2006 is relatively low cannot be attributed to known, specific factors.

Witnesses: I. Chan
H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #4

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / page 6 / Table 3

With respect to Table 3, please explain how a negative UAF can exist – per year 2004 where there is a negative volume of 22,406?

RESPONSE

As explained in the response to Board Staff Interrogatory, at Exhibit I, Issue C5, Schedule 1.3, Unaccounted for Gas ("UAF") represents the difference between the gas delivered into the distribution system being billed by the third party transmission pipelines (TCPL and Union Gas), and metered consumption of the Company's 1.96 million customers.

A negative UAF can exist when the gas delivered into the distribution system being billed by the third party transmission pipelines are lower than the metered consumption. Please also see the response to Board Staff Interrogatory, at Exhibit I, Issue C5, Schedule 1.9 for further explanation on the measurement variation sourced from the third party transmission companies.

Witnesses: I. Chan
H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #5

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / para 1

Please file the proposed language for the UAFVA for 2013.

RESPONSE

The proposed language for the 2013 UAFVA is filed in evidence at Exhibit D1, Tab 8, Schedule 1, page 10.

Witnesses: I. Chan
H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #6

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1

Please indicate what financial incentives exist for the Company to improve management of unaccounted for volumes of gas under the current rate setting and variance account regime.

RESPONSE

Please see the response to Board Staff Interrogatory #7 at Exhibit I, Issue C5, Schedule 1.7.

Witnesses: I. Chan
K. Culbert
D. Small
R. Small

BOARD STAFF INTERROGATORY #7

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / para 1

Board staff proffers that it may improve the balance of shareholder and ratepayer interests if the Company had appropriate financial incentives to improve the management of gas losses on its system. Please provide the Company's view of the following proposal for UAFVA clearances in 2013 and forward:

> Any amounts in excess of, or less than, the variance account pivot point will be shared 50:50 as between ratepayer and the shareholder.

RESPONSE

Please refer to the responses to Exhibit I, Issue C5, Schedules 1.6 and 1.8 as they also form the Company's response.

The Unaccounted for Gas Variance Account (UAFVA) was established and approved by the Board within regulatory proceeding at RP-2001-0032. It is appropriate to continue the use of the UAFVA for the following reasons:

1. As noted at Exhibit D2, Tab 6, Schedule 1, the Company has been taking multiple steps to proactively address the factors causing UAF and the associated volatility that the Company can control. However, there are some factors beyond the Company's control, such as metering variations from third party transmission pipelines and metering technology. In addition to this uncontrollability issue, UAF is, by nature, difficult if not impossible to accurately forecast for any given year since UAF occurrence does not necessarily follow any pattern and can be caused by a multiplicity of factors that may occur intermittently in different years.[1]

2. Protect ratepayers and shareholders from benefitting at the expense of the other party related to a variance in the forecast amount that has high level of

[1] Please refer to Chart 1 of Exhibit D2, Tab 6, Schedule 1.

Witnesses: I. Chan
K. Culbert
D. Small
R. Small

uncertainty. Exhibit I, Issue C5, Schedule 1.2, illustrates that the balance of shareholder and ratepayers interests are well represented by the current UAFVA. During 2002-2010, ratepayers were refunded to $40.2 million in total on account of UAFVA.

In effect, UAF is an inherent risk that is associated with the gas distribution business. The amount at risk can be material and it fluctuates with the volatility of the gas commodity cost as shown at Exhibit I, Issue C5, Schedule 1.2. A departure from the current UAFVA approach will likely increase the risk profile of the Company.

Further, the Company's UAF percentage has been consistently lower than the industry average of 172 utilities within North America. Please see Chart 1 on page 3 of Exhibit D2, Tab 6, Schedule 1.

In consideration of the above, the Company views that the current UAFVA approach provides providing a just, fair, symmetric and reasonable rate making mechanism to both ratepayers and shareholders. Also, given the significant degree of unpredictability and uncontrollability in the factors underlying the determination of the UAF forecast from year to year, the use of a pivot point will likely not enhance the outcomes, but instead will adversely further increase the risk profile of the Company.

Accordingly, the Company does not plan to propose any changes to the UAFVA methodology going forward.

Witnesses: I. Chan
K. Culbert
D. Small
R. Small

BOARD STAFF INTERROGATORY #8

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1

In the Company's view, what would be an appropriate financial incentive structure to improve the management of unaccounted for volumes of gas?

RESPONSE

Please see the response to Board Staff Interrogatory #7 at Exhibit I, Issue C5, Schedule 1.7.

Witnesses: I. Chan
K. Culbert
D. Small
R. Small

BOARD STAFF INTERROGATORY #9

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Ex. D3 /Tab 4/ Sch 1 / page 5 / Table 2

With respect to Table 2, please explain why the Board-approved volume increased dramatically in 2011.

RESPONSE

UAF volumes are forecast annually using a regression model that is updated for the most recent actual data. Please refer to Exhibit D2, Tab 6, Schedule 1 for factors impacting historical actual UAF volumes. To the degree that the measurement variability is sourced from the third party transmission companies, TCPL and Union Gas, and is within the industry tolerance level of +/-2% for each company, the year over year variability of fluctuation would be beyond the Company's control. Chart 1 of Exhibit D2, Tab 6, Schedule 1, illustrates that the Company's average UAF % during 2006 to 2011 is 0.6%. This percentage is well within the industry's tolerance level of +/-4% for the two third party transmission companies' measurement variability, i.e. +/-2% for TCPL and +/-2% for Union Gas.

Further, given that the regression model's UAF forecast is a function of the number of customer active meters (or unlocks), the 2011 UAF forecast is expected to be higher than the historical actual as a result of the ongoing customer growth within the franchise area, all else being equal. The rationale for using unlocks as an explanatory variable in the regression model is that higher unlocks will lead to higher throughput volumes, hence an increase in UAF volumes holding other things constant.[1]

[1] Please refer to Exhibit I, Issue C2, Schedule 11.1, for historical actual customer growth.

Witnesses: I. Chan
H. Sayyan
M. Suarez

APPRO INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Reference: Exhibit D2, Tab 6, Schedule 1 (UAF)
Exhibit B1, Tab 5, Schedule 1 (Storage Capital Expenditures)

Enbridge has provided information on unaccounted for gas

a) Enbridge has proposed a 0.63% UAF level for 2013. Please specify by rate class how the costs (or the provision of gas in kind) associated with UAF are recovered, including any variances between forecast and actual UAF.

b) Please advise of the rationale for the large fluctuation in UAF between 2006 and 2009 (a tenfold increase) illustrated in Table 4.

c) Enbridge has indicated that one of the reasons for UAF is third party damage to its underground piping. Does Enbridge estimate the lost gas that occurs during a line break and if so does it recover the related lost gas costs in these situations? If so is UAF adjusted to reflect recover of gas costs?

d) In the second reference, Enbridge has indicated that it is spending $21 million to update dated metering facilities at the Wilkesport metering station and has further conducted extensive 3D seismic programs to better understand the storage facilities as this could be a source of UAF. Please provide more details on the potential UAF amounts that could be attributed over the last 10 years to storage metering error and migration of gas in the storage pool to non-cycling regions of the pools.

e) Enbridge is proposing the use of the average of the last 5 years as the estimate to use for 2013, which includes the results for 2009 which has unusually high UAF values. This 5 year average (0.63%) is an increase of 0.03% (5% increase) over the 2012 estimate. However at the same time Enbridge is indicating that it has many programs underway to manage UAF including:

Witnesses: I. Chan
J. Collier
A. Kacicnik
B. Pilon

- Significantly shorter average service life for meters, which was driven by changes to the testing standards by Measurement Canada (D2 Tab 2 Schedule 1, page 37)
- Implementation of AGA best practices for metering standards
- Updating Wilkesport metering facilities
- Drilling observation and new injection and withdrawal wells to investigate and recover LUF
- Use of AGA best practices and practices beyond best practices to manage UAF
- Implementation of a province wide one call system for locates
- Total damages to facilities have declined 36% over the last 10 years
- Recapture of gas that might otherwise be otherwise lost during operating activities
- Cast iron and other old main replacement programs
- Other capital replacement programs

Please explain why UAF is proposed to increase when all of these extensive capital and operating programs suggest that UAF should decline.

f) Please explain in detail how UAF is allocated among rate classes.

g) For unbundled distribution customers that do not rely on Enbridge providing balancing services, is the UAF in rates the same as for customers where Enbridge provides the balancing services? If so please explain. If yes, then please also provide the following for customers receiving balancing service:

   i. Please indicate the total volume of gas consumed by such rate classes
   ii. Please indicate what percentage of gas references in i) above flows in and out of storage
   iii. Please indicate what percentage of gas referenced in i) above is delivered directly to the city gate by a transmission company and does not flow through storage.

h) Please describe in detail how UAF is estimated for unbundled distribution customers.

i) Enbridge notes that it has check measurement at the custody transfer locations with Union and TCPL to double check the accuracy of their meters and billing information. Please comment on the accuracy of these other utilities' meters and the number of times that the check measurement has been used over the last 5 years to adjust billed volumes from Union and TCPL.

RESPONSE

a) UAF is allocated to all bundled customers based on the bundled annual deliveries allocator, and recovered from all bundled customers through the Company's bundled delivery rates. Unbundled customers provide UAF in kind, since they do not pay for UAF in their rates. Variances between forecast and actual UAF are tracked in the UAF Variance Account. The balance in this account is allocated to customer classes using the bundled annual deliveries allocator, and cleared in conjunction with other deferral and variance accounts annually.

b) Please refer to the responses to Board Staff Interrogatory, at Exhibit I, Issue C5, Schedule 1.3 and part e) below.

c) It is known to be very difficult to determine the amount of gas lost related to a damaged pipeline as there are no metered volumes recorded. Further, the cost of gas is relatively minor compared to the cost of the physical damage of the pipeline. Therefore, only approximate charges are calculated for the gas lost. The calculation is based upon type of damage, material of the pipe, size of the pipe, size of the hole, number of minutes in system gas escape, and pressure of the pipe. In order to minimize the administrative burden and costs for the reasons mentioned above, the lost gas costs are not segregated from the total amount recovered which is credited to O&M.

d) Exhibit B1, Tab 5, Schedule 1 only mentions potential causes for the Lost and unaccounted for volumes (“LUF”). The LUF allowance represents the provision for anticipated physical inventory discrepancies between the metered values of Tecumseh storage inventories, as reported in operational measurement reports, and the pressure derived balances of Tecumseh storage as calculated from reservoir engineering’s analysis. It is anticipated that a more accurate assessment of the LUF volumes will be available after the storage capital projects mentioned in Exhibit B1, Tab 5, Schedule 1, are completed. These projects are (1) Storage Pool Gas Metering Replacement, (2) 3D Seismic Program and (3) Reservoir Observation Well Drilling.

   As defined at Exhibit D2, Tab 6, Schedule 1, Paragraph 5, Unaccounted for Gas (“UAF”) represents the difference between the gas delivered into the distribution system being billed by the third party transmission pipelines and metered consumption of the Company's 1.96 million customers. Therefore, UAF is not impacted by the storage pool metering upgrades or migration of gas in the storage pool as described at Exhibit B1, Tab 5, Schedule 1 and above.

e) The Company does not propose the use of the average of the last 5 years as the UAF forecast. As stated in Exhibit D3, Tab 4, Schedule 1, the Company utilizes a regression model to generate the Company's 2013 UAF forecast. Given that the regression model's UAF forecast is a function of the number of customer active meters (or unlocks), the 2013 UAF forecast is expected to be higher than the 2012 estimate as a result of customer growth within the franchise all else being equal. The rationale of using unlocks as an explanatory variable in the regression model is that higher unlocks will lead to higher throughput volumes sourced from third party transmission pipelines and hence UAF volumes holding other things constant.

Results from Table 4 of Exhibit D2, Tab 6, Schedule 1 illustrate the Company's regression model approach performs very well compared to other known forecasting methodologies used in North America.

Please refer to the response to part (d) above for the reasons why updating Wilkesport metering facilities and drilling observation wells is relevant to LUF but not UAF.

As mentioned in Exhibit D2, Tab 6, Schedule 1, other than measurement variation, the other UAF factors, (leaks in the pipe; accidental damage to the pipe; release to the atmosphere during normal maintenance operations or theft), do impact the distribution system's safety and reliability which is the Company's top priority. Therefore, the Company has been, on an ongoing basis, undertaking multiple initiatives and steps to manage these factors.

To the degree that measurement variability relates to third party transmission companies, TCPL and Union Gas, and is within the industry tolerance level of +/-2% for each company, the year over year variability or fluctuation is beyond the Company's control. Chart 1 of Exhibit D2, Tab 6, Schedule 1, illustrates that the Company's average UAF% during 2006-2011 is 0.6%. This percentage is well within the total tolerance level of +/-4% for the two third party transmission companies' measurement variability, i.e. +/-2% for TCPL and +/-2% for Union Gas.

It is known that gases are more difficult to measure than other items, as measured volumes are highly affected by temperature and pressure. Measurement Canada also observes that gas meter measurement is "a pretty complicated mechanism".[1] An article from the AGA stated that the primary cause of UAF is meter uncertainty.[2] As measurement is a sophisticated but imperfect estimation process, the accuracy of all of the meter information can only be evaluated within the required percentage of tolerance instead of an absolute value. Therefore, some uncertainty in UAF always exists. Best practices can reduce but not eliminate the UAF uncertainty.

f) UAF is allocated to all bundled customers based on the bundled annual deliveries allocator.

g) No. Bundled customers receive a number of services from Enbridge (i.e. a bundled service) and pay for UAF in rates. Unbundled customers provide UAF in-kind. Further, unbundled customers provide UAF in-kind only for services they receive from Enbridge. If an unbundled customer contracted for an unbundled distribution service from EGD, the customer would only be required to provide the in-kind UAF volume requirement associated with the distribution service. Therefore, the UAF recovered in rates for a bundled customer versus the UAF obligation for an unbundled distribution customer would not be the same. Note that, unbundled customers' deliveries and consumption are not included in the actual UAF presented on Chart 1 of Exhibit D2, Tab 6, Schedule 1. That means they are not included in the UAFVA calculation for the reasons mentioned above.

h) UAF is forecast using a regression model that estimates the relationship between historical UAF on a system-wide basis and the level of total unlocked customers. The selected model is tested against a number of alternative models to ensure that the model with the lowest forecast error is selected. Please see a detailed description of the UAF methodology at Exhibit D3, Tab 4, Schedule 1. The unbundled UAF% pursuant to the rate handbook is calculated as a percentage of this UAF forecast of the sendout volumes forecast.

i) As stated in Exhibit D2, Tab 6, Schedule 1, paragraph 16, the Company has installed check meters that are operated in accordance with Canada's Electricity and Gas Inspection Act and Regulations for each city gate station to monitor the accuracy of these custody transfer meters on a daily basis and whether they are within the +/- 2% tolerance permitted by applicable agreement. If the difference between custody transfer and check meter information falls outside this +/- 2% tolerance, the Company will investigate the variance and seek a resolution with TCPL and Union Gas accordingly.

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[1] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm03961.html
[2] American Gas Association. (2009). Lost and Unaccounted For Gas Cost Recovery Mechanisms. Natural Gas Rate Round-Up

Witnesses: I. Chan
J. Collier
A. Kacicnik
B. Pilon

Over the last five years, there have been five days or fewer per year on average that one of the Company's interconnects with TCPL has had a measurement discrepancy greater than 2% and eventually the Company's check measurement has been used for the custody transfer measurement. In all cases, this has occurred at TCPL city gate stations; there have been no such instances at Union Gas stations.

Witnesses: I. Chan
J. Collier
A. Kacicnik
B. Pilon

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Ref: Exhibit D2, Tab 6, Schedule 1

Please provide a version of Chart 1 that shows the UAF % comparison of EGD with Union Gas. Union Gas data can be found at Tab 2, Schedule 2 of Updated Exhibits D3, D4, D5 and D6 in EB-2011-0210.

RESPONSE

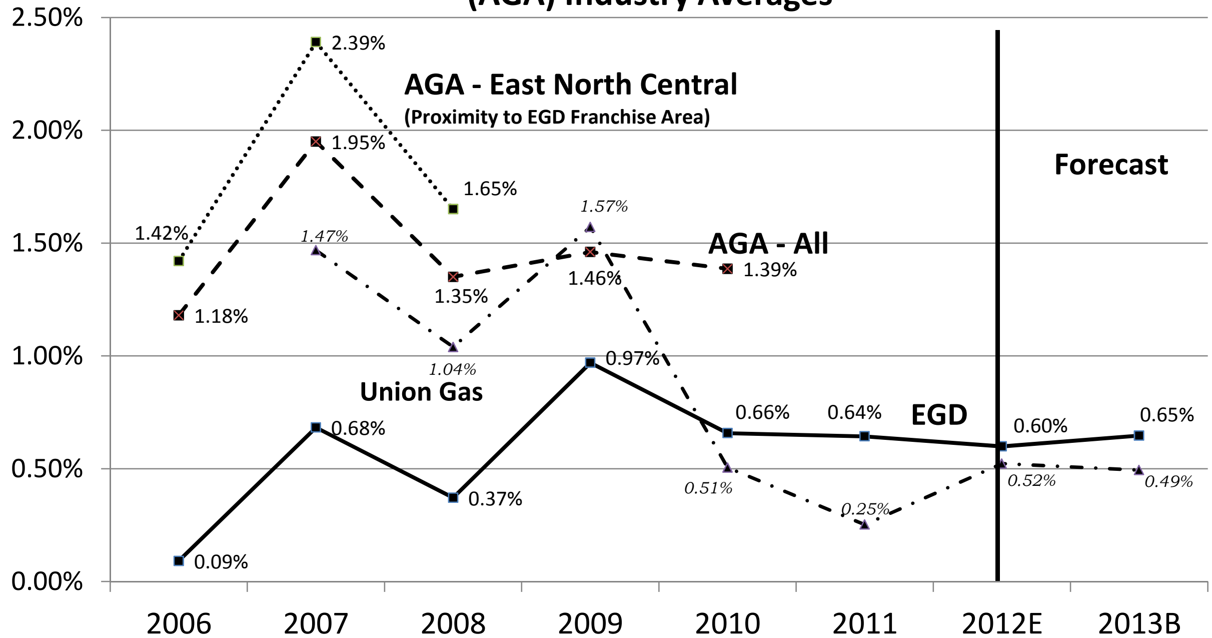
An updated version of Chart 1 is presented on the next page.[1]

As different gas utilities have different metering variations and operational and uncontrollable external factors of UAF,[2] these factors of UAF have to be assessed when comparing the Company's UAF with another specific utility. It may be more accurate to undertake the comparison in relation to the AGA industry averages of 172 utilities within North America, because the large sample will largely balance out these factors. Examples of these factors are number of total meters, number of total residential meters, utilization of third party transmission pipelines (i.e., reliance on their meters and billings) or own transmission pipelines, number of construction activities within the franchise area, characteristics of the distribution system and characteristics of the geographic area served.

[1] Actual and forecast UAF volumes for Union Gas are obtained from updated Exhibits D3-D6. Forecast in-franchise throughput volumes are obtained from Exhibits C3-C4 instead from Exhibits D3-D6 as the later ones include ex-franchise volumes which are not relevant to the in-franchise UAF volumetric comparison.

[2] Please refer to Exhibit D2, Tab 6, Schedule 1 for a detailed description of these factors of UAF.

Chart 1: UAF % Comparison with American Gas Association (AGA) Industry Averages*



*Note: American Gas Association. (2010). Lost and Unaccounted For Gas. Financial and Operational Information Series.

- The Company's percentage is based upon 12 months ending December 31 of the reporting year.
- The AGA's percentages are based upon 12 months ending June 30 of the reporting year.
- AGA's 2009 and 2010 actual percentages are based on preliminary simple averages of raw data obtained from the 2011 Best Practices Benchmarking Data Report.

FRPO INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Given EGD's "Pool Metering Upgrades" what is resulting expectation in UAF?

a. As a result, what is EGD proposing in terms of adjusting the formula for sharing with ratepayers, the cost of UFG?

RESPONSE

It is anticipated that an enhanced assessment of the Lost and unaccounted for volumes ("LUF") will be available after the storage capital projects mentioned in Exhibit B1, Tab 5, Schedule 1, are completed. These projects are (1) Storage Pool Gas Metering Replacement, (2) 3D Seismic Program and (3) Reservoir Observation Well Drilling. The LUF allowance represents the provision for anticipated physical inventory discrepancies between the metered values of Tecumseh storage inventories, as reported in operational measurement reports, and the pressure derived balances of Tecumseh storage as calculated from reservoir engineering's analysis.

As defined at Exhibit D2, Tab 6, Schedule 1, paragraph 5, Unaccounted for Gas ("UAF") represents the difference between the gas delivered into the distribution system being billed by the third party transmission pipelines and the metered consumption of the Company's 1.96 million customers. Therefore, UAF is not impacted by the storage pool metering upgrades described at Exhibit B1, Tab 5, Schedule 1.

The purpose of the UAFVA ("Unaccounted for Gas Variance Account") is to protect ratepayers and shareholders from benefitting at the expense of the other party related to a variance in the forecast amount. EGD is not proposing any adjustment to the current UAFVA methodology.

Witnesses: I. Chan
B. Pilon

VECC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Reference: Exhibit D2 Tab 6 Schedule 1 and Table 4

a) Confirm that Union uses the 3-year Weighted Average method and the 3 year average data are for Union. If not, insert a Column for Union.

b) Update Table 4 for 2011 Actuals for the Company and 3 year weighted averages (and/or for Union).

c) Include Union's Actuals and Forecast 2011-2012 from EB-2011-0210.

RESPONSE

a) It is confirmed that Union Gas uses the three year weighted average method. The three year weighted average results that were reported in Table 4 were not for Union Gas. As each gas utility has different metering variations, operational and uncontrollable external factors[1], a forecast methodology that works well for one gas utility may not work well for another one. Therefore, five-year average and three-year weighted average forecasting methodologies are performed using the Company's historical actual data and the results are set out in Table 4 of Exhibit D2, Tab 6, Schedule 1. Table 4 illustrates that the Company's regression model approach is the best performing methodology among the known forecasting methodologies, excluding the subjective judgement methodologies, used in North America in terms of forecast accuracy. A column for Union's 3-year weighted average is added to the updated Table 4 in column 10.

b) and c) Please refer to the updated Table 4 which follows.

[1] Examples of these factors are number of total meters, utilization of third party transmission pipelines (i.e. reliance on their meters and billings) or own transmission pipelines, geographic area, etc.

Witness: I. Chan

Table 4: Comparison of Forecast Performance - UAF Forecasting Methodologies

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
					Forecast vs Actual Variance						Forecast Variance	
Year	The Company's Actual	The Company's Regression Model - In-Sample Forecast	The Company's 3-Year Weighted Average	The Company's 5-Year Average	The Company's Model vs Actual	The Company's 3-Year Weighted Average vs Actual	The Company's 5-Year Average vs Actual	Union Gas Actual	Union Gas Board Approved	Union Gas 3-Year Weighted Average	Union Gas Board Approved vs Actual	Union Gas 3-Year Weighted Average vs Actual
2006	10,274	46,636	12,728	19,742	36,362	2,454	9,468	154,015	142,322	142,322	(11,693)	(11,693)
2007	83,823	51,311	(65,967)	6,676	(32,512)	(149,790)	(77,147)	203,713	147,478	147,478	(56,235)	(56,235)
2008*	44,424	55,691	67,498	21,584	11,267	23,074	(22,840)	143,880	147,478	*147,478*	3,598	*3,598*
2009*	110,917	58,108	65,733	26,186	(52,809)	(45,185)	(84,731)	201,845	147,478	*147,478*	(54,367)	*(54,367)*
2010	72,104	62,183	89,070	52,851	(9,920)	16,967	(19,253)	67,283	147,478	152,047	80,195	84,764
2011	73,355	66,870	85,625	64,308	(6,485)	12,270	(9,047)	35,668	147,478	183,684	111,810	148,016
2012**	68,134		89,254	76,925						76,356		
2013**	73,092		71,267	73,787						70,253		
				Mean Absolute Error:	24,893	41,623	37,081		52,983			59,779

*Per Union Gas's response, forecasts for 2008 and 2009 are not available as they were not required for the Incentive Regulation filing.
In order to faciliate comparison and for completeness, forecasts for 2008 and 2009 are assumed to be same as 2007's.
**Col. 1 of years 2012 and 2013 represent regression model forecast numbers.

Witness: I. Chan

VECC INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 5: Is the forecast level of Unaccounted For (UAF) gas volumes appropriate?

Reference: Exhibit D3 Tab 4 Schedule 1 Table 2

a) Please expand Table 2 to include throughput volumes, 2011 actuals & 2012E and 2013F

RESPONSE

Please see the expanded Table 2 which includes actual throughput volumes to 2011 in addition to the 2012 Board-Approved and 2013 Forecast UAF amounts and throughput volumes.

Table 2
UAF Actuals vs Board Approved -- Modified for Interrogatory Response

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*
Calendar Year	**UAF Actual (10^3m^3)**	**UAF - Board Approved (10^3m^3)**	**Throughput Volumes (10^3m^3)**
2006	10,274	39,162	11,251,570
2007	83,823	39,444	12,275,870
2008	44,424	39,444	11,970,534
2009	110,917	31,841	11,442,705
2010	72,104	37,795	10,963,467
2011	73,355	64,211	11,405,345
2012 Board-Approved		68,925	11,376,396
2013 Forecast		73,092	11,302,716

Witnesses: H. Sayyan
M. Suarez

BOARD STAFF INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Ex. C1 /Tab 4/ Sch 1 / p1

Please provide a background explanation of how the opportunities for Transactional Services ("TS") arise. Please address at least the following questions:

1. How are TS opportunities identified by Enbridge?
2. Which assets are available for revenue generation?
3. How the revenues are derived and accounted for?

RESPONSE

EGD will not enter into any Transactional Services ("TS") deal if it will impede the ability of the utility to meet the needs of its customers either operationally or by increasing costs.

The vast majority of TS deals are for daily, monthly or seasonal type transactions.

The availability of daily transportation and storage assets for TS optimization is determined by the EGD Gas Control staff. The level of availability is then passed on to the Gas Supply and TS groups each day. Potential TS transactions are overlaid on the supply and demand daily profiles to determine if the deal can be completed.

Availability of assets are determined by the combined assessments/reviews of both Gas Control as well as the broader Energy Supply and Policy group in response to market opportunities and deal offerings from third parties. Similar to daily transactions, potential monthly and/or seasonal deals are overlaid on the supply and demand profiles in order to create a conservative view of availability.

As part of the deal consideration, the TS group observes and tracks market prices and spreads for locations and terms that align with utility assets. Again, if the deal can be executed without jeopardizing utility operations, the TS group negotiates a fair market price with the counterparty.

In terms of the assets optimized by TS, EGD looks for opportunities related to both storage and transportation assets. Storage deals are almost exclusively “park” deals in which a counterparty will pay EGD to take delivery of gas on a particular day(s) that will then be re-delivered to the counterparty at a future date. In terms of the transportation assets, TS has optimized capacity on a number of pipelines (including TCPL, Union, Vector and Alliance). The majority of transportation-related volumes are optimized as exchanges in which TS will receive a volume of gas at one location and re-deliver it on the same day at another location. In addition to exchanges, TS also executes capacity releases and/or assignments with third parties.

All TS deals are fee-based transactions (net of any costs such as fuel charges). Assets have never been acquired on behalf of TS as all contracting decisions are made strictly with the Company’s operational needs in mind. TS was established and continues to be operated with the aim of optimizing utility assets such that revenue can be generated for the ratepayer without negatively impacting the primary aims of the Company. Currently, all TS revenue (net of costs such as incurred transportation fuel) is split 75/25 for transportation deals and 90/10 for storage deals (ratepayer/shareholder respectively).

For every net dollar of storage revenue generated 90 cents is identified as customer revenue and for every net dollar of transportation revenue generated 75 cents is identified as customer revenue. When the sum of these two amounts equals the amount included in rates then, any excess amount goes to the TSDA for future disposition.

BOARD STAFF INTERROGATORY #2

INTERROGATORY

C- Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Ex. C1 /Tab 4/ Sch 1 / p4

Please provide the actual and forecast financial and operating information relevant to TS for the years 2007 through 2013. Please disaggregate the amounts into transportation and storage, and include the relevant operating costs and the amounts shared between ratepayers and shareholders.

RESPONSE

For Fiscal Years 2007 through to 2012 the Company included a forecast of $8.0 million in Transactional Services revenue as a reduction to costs to be recovered in rates. For 2013 the Company is proposing that the forecast be reduced to $6.0 million. For purposes of designing rates the Company assumes the Transactional Services revenue included in rates is split 50/50 between Storage and Transportation Revenue. Please see the response to Energy Probe Interrogatory, at Exhibit I, Issue C3, Schedule 7.2.

The attached table provides the actual Transactional Services revenue for Fiscal 2007 – 2011 and an estimate for 2012.

Witnesses: V. Krauchek
J. Sarnovsky

Table 1

Item #	Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8
	Fiscal 2007 - Actual	Storage Optimization $(000's)	Pipeline Optimization $(000's)		Fiscal 2008 - Actual	Storage Optimization $(000's)	Pipeline Optimization $(000's)	Total Revenue $(000's)
1.	Net Revenue	10,302.0	9,902.1	20,204.1	Net Revenue	8,589.1	8,994.4	17,583.5
	Rate Payer - %	90.00%	75.00%		Rate Payer - %	90.00%	75.00%	
2.	Rate Payer - $(000's)	9,271.8	7,426.6	16,698.4	Rate Payer - $(000's)	7,730.2	6,745.8	14,476.0
3.	Amount Included in Rates			(8,000.0)	Amount Included in Rates			(8,000.0)
4.	Amount Transferred to TSDA			8,698.4	Amount Transferred to TSDA			6,476.0
	Fiscal 2009 - Actual	Storage Optimization $(000's)	Pipeline Optimization $(000's)		Fiscal 2010 - Actual	Storage Optimization $(000's)	Pipeline Optimization $(000's)	
5.	Net Revenue	9,850.1	8,262.7	18,112.8	Net Revenue	8,960.6	9,599.9	18,560.5
	Rate Payer - %	90.00%	75.00%		Rate Payer - %	90.00%	75.00%	
6.	Rate Payer - $(000's)	8,865.1	6,197.0	15,062.1	Rate Payer - $(000's)	8,064.5	7,199.9	15,264.5
7.	Amount Included in Rates			(8,000.0)	Amount Included in Rates			(8,000.0)
8.	Amount Transferred to TSDA			7,062.1	Amount Transferred to TSDA			7,264.5
	Fiscal 2011 - Actual	Storage Optimization $(000's)	Pipeline Optimization $(000's)		Fiscal 2012 - Estimate	Storage Optimization $(000's)	Pipeline Optimization $(000's)	
9.	Net Revenue	3,464.5	16,318.5	19,783.0	Net Revenue	4,671.9	16,673.3	21,345.2
	Rate Payer - %	90.00%	75.00%		Rate Payer - %	90.00%	75.00%	
10.	Rate Payer - $(000's)	3,118.1	12,238.9	15,356.9	Rate Payer - $(000's)	4,204.7	12,505.0	16,709.7
11.	Amount Included in Rates			(8,000.0)	Amount Included in Rates			(8,000.0)
12.	Amount Transferred to TSDA			7,356.9	Amount Transferred to TSDA			8,709.7

BOARD STAFF INTERROGATORY #3

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Ex. C1 /Tab 4/ Sch 1 / para 11

With respect to the proposal to capture the negative variances in the TS deferral account, is this a new proposal that is different from the currently agreed-upon treatment? Please also clarify the specifics of the proposal to capture positive variance from the forecast level of TS revenue.

RESPONSE

This is a new proposal being brought forward by the Company. Please see the response to Energy Probe Interrogatory #2 at Exhibit I, Issue C6, Schedule 7.2, part b).

Witnesses: V. Krauchek
J. Sarnovsky

BOARD STAFF INTERROGATORY #4

INTERROGATORY

C- Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Ex. C1 /Tab 4/ Sch 1 / para 11

Please file the draft accounting language that would give effect to the Company's proposal for the TS deferral account in 2013.

RESPONSE

The following is the draft accounting language for the proposed Transactional Services deferral account for 2013.

> The purpose of the 2013 TSDA is to record either, the ratepayer share of the net revenue from transportation and storage related transactional services, in excess of the $6.0 million revenue forecast and the operation and maintenance costs associated with storage related transactional services, or any negative variances which result in comparison to the $6.0 million forecast.
>
> Net transportation related transactional services revenue will employ a 75:25 sharing mechanism between the Company's ratepayers and shareholders and the net storage related transactional services revenue will employ a 90:10 sharing mechanism between ratepayers and shareholders.
>
> Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, re-direct charges, etc.
>
> Simple interest is to be calculated on the opening monthly balance of the 2013 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2013 TSDA, together with carrying charges, will be disposed of in a manner determined by the Board in a future rate hearing.

Witnesses: J. Sarnovsky
V. Krauchek
K. Culbert
R. Small

BOARD STAFF INTERROGATORY #5

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Ex. C1 /Tab 4/ Sch 1 / para 11

Please file the currently approved accounting order language for the existing TS deferral account. Please also file the wording of the currently approved revenue sharing arrangement.

RESPONSE

The currently approved 2012 TSDA language, which follows, is a copy of page 6 of Appendix C from the EB-2011-0277, 2012 Board Rate Order.

Witnesses: V. Krauchek
J. Sarnovsky

ACCOUNTING TREATMENT FOR A
TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
("2012 TSDA")

For the 2012 Fiscal Year
(January 1, 2012 to December 31, 2012)

The purpose of the 2012 TSDA is to record the ratepayer share of the net revenue, from transportation and storage related transactional services, in excess of the $8.0 million ratepayer guarantee and the operation and maintenance costs associated with storage related transactional services.

As determined in the NGEIR Decision with Reasons (EB-2005-0551), there is a distinction, and differing sharing mechanisms, associated with transportation related and storage related transactional services. Net transportation related transactional services revenue will employ a 75:25 sharing mechanism between the Company's ratepayers and shareholders, but net storage related transactional services revenue will employ a 90:10 sharing mechanism between ratepayers and shareholders.

Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, re-direct charges, etc.

In EB-2005-0001, the Board determined that the operating and maintenance expenses (O&M) such as salaries, benefits, promotion, legal fees, etc. are properly recovered from ratepayers through rates outside of the TS sharing mechanism. This methodology remains in effect for O&M related to transportation related transactional services, but no longer applies to O&M related to storage related transactional services. The NGEIR Decision with Reasons (EB-2005-0551) determined that incremental O&M related to providing storage related transactional services will now be applied against the corresponding net revenues.

Simple interest is to be calculated on the opening monthly balance of the 2012 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2012 TSDA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

APPRO INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Reference: Exhibit C1, Tab 4, Schedule 1, paragraph 5

Enbridge discusses greater gas-fired generation summer demand and greater winter shale gas supplies both of which contribute to depressing the price of storage. Enbridge also indicates that there is a slight oversupply in storage in the US Northeast and Ontario due to increases in capacity.

a) Please confirm that gas-fired generation also is used in winter which increases the demand for gas and hence winter commodity prices.

b) Please confirm that shale gas supplies are also produced in summer which acts to depress summer prices.

c) Please provide a list of these new storage projects that result in additions to storage capacities (bcf) and deliverability (bcfd) since 2006 that are contributing to the storage oversupply. List these as a percentage of the total storage capacity and deliverability in the region.

d) On what basis does Enbridge conclude that there is storage overcapacity in the region?

RESPONSE

The evidence at Exhibit C1, Tab 4, Schedule 1, paragraph 5, was intended to draw attention to the effects that a number of changes in the natural gas landscape are having on the value of storage. While it is true there is demand for gas-fired generation in the winter, the increase in demand for gas-fired generation in the summer is thought to be having a greater impact on summer prices than the winter demand has on winter prices. Similarly, the availability of Marcellus supply is apparently having a greater impact on winter prices than on summer prices. EGD drew these conclusions from

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

industry commentary including an ICF report submitted to the Ontario Energy Board on August 20, 2010.

Within that same report ICF also identified that from 2000 to 2006 new storage capacity had increased, on average, by 46 Bcf/year and that since that time, capacity additions had averaged 109 Bcf/year. The report included a number of storage projects over the 2006 to 2009 period. The following table from the ICF report, page 48, is provided her for your reference.

Exhibit 32: U.S. and Canada Natural Gas Resource Base, in Tcf

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[1]
Alaska	7.7	153.6	161.3	0.0
West Coast Onshore	2.3	24.6	27.0	0.3
Rockies & Great Basin	66.7	388.3	454.9	37.9
West Texas	27.6	47.7	75.3	17.5
Gulf Coast Onshore	70.1	684.7	754.8	476.9
Mid-continent	37.0	205.0	241.9	133.9
Eastern Interior [2]	18.6	795.7	814.3	728.1
Gulf of Mexico	14.0	238.6	252.5	0.0
U.S. Atlantic Offshore	0.0	32.8	32.8	0.0
U.S. Pacific Offshore	0.8	31.7	32.5	0.0
WCSB	60.4	664.0	724.4	508.8
Arctic Canada	0.4	45.0	45.4	0.0
Eastern Canada Onshore	0.0	12.8	12.8	0.0
Eastern Canada Offshore	0.5	71.8	72.3	0.0
Western British Columbia	0.0	10.9	10.9	0.0
US Total	**244.7**	**2,602.6**	**2,847.3**	**1,394.5**
Canada Total	**61.3**	**804.5**	**865.8**	**508.8**
US and Canada Total	**306.0**	**3,407.1**	**3,713.0**	**1,903.3**

1 . Shale Resource is a subset of Total Remaining Resource   Source: ICF International
2. Resource estimate for Eastern Interior assumes drilling levels are held constant at today's level over time, reflecting restricted access to the full resource development.

As well, EGD has noticed that since it has been going out with RFP's for market based storage, prices for storage service have continued to decline. Please see the response to CME Interrogatory, at Exhibit I, Issue D2, Schedule 4.3.

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

APPRO INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Reference: Exhibit C1, Tab 4, Schedule 1, paragraph 11
Exhibit D1, Tab 2, Schedule 1, paragraph 13

In the first reference, Enbridge indicates that it is proposing to reduce TS revenue forecast to $6 million in rates and capture negative variances from forecast in a deferral account and recover from rate payers in the following year. Further that sharing ratios for storage and transportation revenue will be shared 90/10 and 75/25 respectively. This lower revenue forecast is noted to reflect unpredictable economics, marketplace and asset base including the proposed elimination of TCPL's FT RAM program. Enbridge has also proposed to contract for 350,000 GJ/d of increased STFT transportation capacity on TCPL in 2012 to meet its proposed 1 in 10 Design Criteria (second reference).

a) Please provide a details illustrating how the $6m TS forecast was derived.

b) TCPL in its RH-3-2011 of its Revised October 31, 2011 Application (section 8.3) indicates that there are other methods to mitigate the loss of RAM including diversions, alternate receipt points and assignment rights. Please explain how these other strategies outlined by TCPL were taken into account in developing the TS transportation forecast.

c) Enbridge indicates that it is contracting for an additional 350,000 GJ/d of STFT at an incremental cost of $66.2 million. Since this is intended to be used to meet the 1 in10 design day requirement, please explain why this transportation would not generate substantial TS transportation revenue 90% of the time, during non-design day periods.

d) Please indicate the months that Enbridge is proposing to contract for STFT service.

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

e) For the months that STFT will be in effect please provide Enbridge's 2013 monthly forecast of basis differential between Empress and Parkway. In the event that Enbridge does not have a forecast, please use the average monthly Empress-Dawn historical basis differential for the last 3 years as a proxy for Empress-Parkway.

f) Please complete the following table:

Calendar Month in 2013 for which STFT will be contracted (a)	Daily STFT Volume (GJ/d) (b)	Days in Month (c)	Empress to Parkway Basis Spread ($/GJ) (Historical or Projected from above) (d)	Percentage of the Time Not Required for Peak Day (e)	Potential TS Monthly Transportation Revenue ($) f=b X c X d X e
				90%	
				90%	
				90%	
				90%	
				90%	
				Total of the Above	

Please provide information on the STFT pricing and how sharing will be calculated including:

i. Please provide the STFT forecasted unit pricing assumptions included in the estimate to determine the $66.2 million annual cost.
ii. To the extent that the actual unit prices incurred for STFT service are different than what is included in the forecast, how will these differences be treated for sharing purposes?

g) Please explain the rationale for the difference in the sharing formula between storage and transportation revenue sources.

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

<u>RESPONSE</u>

a) The reduction in the $8.0 million guarantee to a $6.0 million threshold was based on all the factors outlined in the Company's evidence at Exhibit C1, Tab 4, Schedule 1.

b) EGD flows its long haul TCPL capacity at 100% load factor and as such has never accrued any long haul credits related to this RAM service. EGD has however, accumulated and optimized RAM credits related to STS each winter. Unlike long haul paths, there are no opportunities for diversion, alternative receipt points or assignment rights with STS contracts: no such flexibility is offered on STS paths which ultimately restricts the revenue opportunities in the absence of STS-RAM credits.

   In looking more broadly at the market, diversions, alternate receipt points and assignment rights have been in place for years as part of the optionality built into various TCPL contracts. RAM was implemented as an "additional" service so its elimination is a reduction in optionality. The restriction of trading opportunities in the market with the elimination of RAM may directly affect the TS group's ability to generate business with counterparties who rely on RAM credits to transact.

c) EGD has not contracted for an additional 350,000 Gj/day of STFT. The Company is proposing that should the Board accept the change in the Design Day Criteria as proposed then there will be a need to acquire an additional 350,000 Gjs/day of STFT with the caveat that there are no other supply alternatives currently available to the Company. The Company also rejects the assumption that because the additional STFT being discussed would be to meet a 1 in 10 probability of a peak day occurrence that that capacity would be available for purposes of TS 90% of the time.

d) See response to part c).

e) See response to part f).

f) As discussed the Company disagrees with the assumption that the STFT would be available for optimization 90% of the time. The determining factor of whether or not the excess capacity will be available for TS will be dependent upon whether or not it will be needed to meet the needs of not only peak day demand but winter daily demand as well. As demonstrated in previous years with procured STFT, the capacity has been heavily utilized both in peak conditions and in meeting daily winter demand. Time is the Company cannot predict a peak day nor actual winter requirements and as such, opportunities for TS cannot be forecast.

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

i. The $66.2 million of unutilized cost was based upon the then current TCPL FT toll, times the level of the transportation capacity that would be unutilized based upon the 2013 budget demand. Please see the response to CCC Interrogatory, at Exhibit I, Issue D2, Schedule 5 1).

ii. To the extent that actual unit prices incurred for STFT service, like gas purchase costs, vary from the forecasted unit prices then those variances will be captured in the Purchased Gas Variance Account ("PGVA") and cleared based upon the Board approved clearing methodology.

g) As per the NGEIR Decision with Reasons, (EB-2005-0551), dated November 7, 2006, differing sharing mechanisms associated with transportation related and storage related transactional services were set out by the Board. Those differing sharing mechanisms are the 90:10 for storage related transactions and 75:25 for transportation related transactions mentioned above. The Company is not proposing any changes to the NGEIR decision.

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

CME INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Reference: Exhibit C1, Tab 4, Schedule 1, pages 1 to 5, and in particular, paragraph 9

The evidence indicates that the Firm Transportation Risk Alleviation Mechanism ("FT-RAM") was introduced by TransCanada PipeLines Limited ("TCPL") as a means of enabling its shippers to mitigate their Unutilized Demand Charges ("UDC"). We understand that the FT-RAM program was first introduced in 2004 and that it has been enhanced since that date. We further understand that FT-RAM credits are in an amount of 110% of UDC that can be applied, in any month, to the purchase of Interruptible Transportation ("IT") services on the TCPL system. We further understand that the FT-RAM credit attribute adds value to the temporary assignment of FT capacity so that if EGD assigns FT capacity, then the assignee gets the benefit of the FT-RAM credits associated with any of that assigned FT space that remains unutilized. In this context and having regard to the statements made in paragraph 9 of Exhibit C1, Tab 4, Schedule 1, please provide the following information:

(a) For each of the years 2004 to 2012 to date, please provide the amount EGD received from TCPL for FT-RAM credits;

(b) For each of the years 2004 to 2012 to date, please advise us of the portion of the FT-RAM credit amounts received that were flowed to ratepayers through EGD's gas supply deferral accounts;

(c) For each of the years 2004 to 2012 to date, please provide details of each of the temporary assignments that EGD made of FT capacity with FT-RAM attributes, including the amount that it received for such assignments and the portion of those amounts that were flowed to ratepayers through EGD's gas supply deferral accounts;

(d) Please explain how the elimination of the FT-RAM (designed to mitigate FT demand charges payable by EGD's ratepayers) could negatively affect

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

Transactional Services ("TS") revenues as stated in line 1 of paragraph 9 of Exhibit C1, Tab 4, Schedule 1 at page 3;

(e) Who are the "marketers" referenced at line 2 of Exhibit C1, Tab 4, Schedule 1, page 4? Are these "marketers" to whom EGD has temporarily assigned FT capacity?

(f) Has EGD been posting revenue attributable to FT-RAM credits to the TS Deferral Account ("TSDA"), i.e. either a portion of the credits themselves, or the value paid by assignees to obtain FT space with FT-RAM credit attributes? If so, then, for each of the years 2004 to 2012 to date, please provide the amounts of such revenues that have been credited to the TSDA rather than to EGD's gas supply deferral accounts; and

(g) Please file the excerpts of any evidence sponsored by EGD in the current National Energy Board ("NEB") proceedings pertaining to TCPL's tolls that relate to EGD's use over the years 2004 to 2012 to date of the FT-RAM, including its temporary assignment of FT capacity possessing FT-RAM credit attributes.

RESPONSE

All TransCanada Mainline capacity is contracted by EGD to meet the needs of its Utility customers. Since the inception of RAM in 2004, EGD has kept its long haul TCPL capacity flowing at 100% load factor. As such, EGD has never accrued any long haul credits related to the RAM service. During periods of reduced demand, typically during the summer months, EGD temporarily releases parts of its long haul TCPL capacity to third parties. Tied to each release is an exchange through which EGD delivers gas at Empress and receives an equivalent volume at Dawn. EGD is kept whole volumetrically at both its receipt and delivery points as would be the case if EGD had retained the capacity. So while these releases may be part of a third parties' RAM strategy, EGD has neither generated nor utilized long haul RAM credits and simply assigns the fee to the value of the exchange transaction.

In November 2007, TCPL attached the RAM feature to STS contracts. EGD operates the STS contracts dependent on the utility demand. RAM credits are accumulated during the winter period when the Utility does not require the maximum STS flow on the day. These credits are then used to offset charges related to the use of IT for managing storage balances. The ratepayer receives 100% of this benefit in the form of lower transportation charges. Any remaining RAM credits are optimized in the secondary market and shared between the ratepayer and shareholder.

a) The table in Attachment 1 provides the monthly TCPL IT charges incurred by EGD and the amount of STS RAM credits received for the period November 2007 to March 2012.

b), c) and f) Please see the responses to FRPO Interrogatory, at Exhibit I, Issue D2, Schedules 8.5 and Schedule 8.6.

d) As mentioned above, the capacity releases of long haul FT capacity that EGD does in the summer may be part of a third parties' RAM strategy. If RAM is discontinued the potential for EGD to optimize its capacity on the Mainline could be reduced. In other words the elimination of RAM may directly affect the TS group's ability to generate business with counterparties who rely on RAM credits to transact. In the event this occurs the optimization revenues could potentially be reduced as well.

e) Yes.

g) Please see in Attachment 2, EGD's response to Information Requests filed in the TCPL Joint Proceeding for Business and Services Restructuring and 2012 and 2013 Mainline Final Tolls (RH-003-2011).

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

TCPL 2625 Interruptible Contract

	Total IT Cost (before tax)	Total IT RAM Credits	Net IT Cost (before tax)
2007			
January	$77,315.56	$0.00	$77,315.56
February	$13,117.50	$0.00	$13,117.50
March	$217,800.00	$0.00	$217,800.00
April	$102,786.65	$0.00	$102,786.65
May	$262,331.56	$0.00	$262,331.56
June	$313,653.75	$0.00	$313,653.75
July	$256,441.95	$0.00	$256,441.95
August	$246,160.22	$0.00	$246,160.22
September	$348,878.62	$0.00	$348,878.62
October	$259,715.77	$0.00	$259,715.77
November	$453,297.09	$418,181.89	$35,115.20
December	$118,457.17	$110,963.48	$7,493.69
	$2,669,955.84	$529,145.37	$2,140,810.47
2008			
January	$337,035.08	$315,009.02	$22,026.06
February	$241,682.66	$225,636.54	$16,046.12
March	$425,167.98	$395,733.21	$29,434.77
April	$253,485.98	$239,100.54	$14,385.44
May	$341,571.00	$0.00	$341,571.00
June	$439,250.27	$0.00	$439,250.27
July	$336,795.12	$0.00	$336,795.12
August	$291,996.64	$0.00	$291,996.64
September	$326,563.36	$0.00	$326,563.36
October	$142,902.15	$0.00	$142,902.15
November	$424,582.79	$390,361.03	$34,221.76
December	$340,201.08	$283,171.01	$57,030.07
	$3,901,234.11	$1,849,011.35	$2,052,222.76
2009			
January	$142,337.97	$132,084.28	$10,253.69
February	$253,220.05	$140,322.99	$112,897.06
March	$333,861.03	$304,873.79	$28,987.24
April	$269,869.80	$157,364.81	$112,504.99
May	$131,109.31	$0.00	$131,109.31
June	$276,274.40	$0.00	$276,274.40
July	$130,409.21	$0.00	$130,409.21
August	$164,781.69	$0.00	$164,781.69
September	$311,907.65	$0.00	$311,907.65
October	$47,783.28	$0.00	$47,783.28
November	$439,182.35	$407,762.77	$31,419.58
December	$166,912.89	$154,904.81	$12,008.08
	$2,667,649.63	$1,297,313.45	$1,370,336.18

2010			
January	$194,686.70	$186,619.28	$8,067.42
February	$224,669.10	$215,536.19	$9,132.91
March	$493,051.03	$472,399.99	$20,651.04
April	$272,723.49	$250,127.24	$22,596.25
May	$173,420.00	$0.00	$173,420.00
June	$151,585.27	$0.00	$151,585.27
July	$112,608.00	$0.00	$112,608.00
August	$173,399.48	$0.00	$173,399.48
September	$222,062.24	$0.00	$222,062.24
October	$4,508.00	$0.00	$4,508.00
November	$430,971.88	$414,299.42	$16,672.46
December	$217,200.00	$208,797.30	$8,402.70
	$2,670,885.19	$1,747,779.42	$923,105.77

2011			
January	$171,323.10	$164,844.42	$6,478.68
February	$169,661.62	$163,098.14	$6,563.48
March	$470,737.75	$442,756.83	$27,980.92
April	$338,711.60	$316,543.58	$22,168.02
May	$172,748.87	$0.00	$172,748.87
June	$91,543.25	$0.00	$91,543.25
July	$177,637.34	$0.00	$177,637.34
August	$236,543.20	$0.00	$236,543.20
September	$148,292.40	$0.00	$148,292.40
October	$55,771.40	$0.00	$55,771.40
November	$647,269.63	$608,795.56	$38,474.07
December	$651,441.63	$612,820.44	$38,621.19
	$3,331,681.79	$2,308,858.97	$1,022,822.82

2012			
January	$402,430.49	$375,871.91	$26,558.58
February	$586,705.36	$540,715.50	$45,989.86
March	$424,047.93	$398,864.51	$25,183.42
	$1,413,183.78	$1,315,451.92	$97,731.86

5. References:

(i) Written Evidence of the MAS, pages 32, line 10-11.
(ii) Written Evidence of the MAS, page 33, lines 20-26 and page 34, lines 1-3.

Preamble

Reference (i) states: “MAS believe that RAM provides a unique tool for Mainline long haul FT shippers to mitigate their risk of unutilized demand charges and differentiates TCPL from other pipelines.”

Further, in reference (ii) MAS states: “TCPL reported that $440 million of RAM credits were applied by Mainline shippers in 2010. [reference cited] These applied credits demonstrate the value of RAM to Mainline shippers who make use of the RAM feature. Clearly the value of these RAM credits are material to Mainline shippers who use RAM and far exceeds any potential derived calculation that eliminating RAM *may* increase annual discretionary revenue that would otherwise lower Mainline tolls. TCPL has added only $50 million of discretionary revenue to reflect their recommendation to eliminate RAM, so this appears to be a poor trade-off.”

TransCanada requires additional information to better understand how EGD extracts value from RAM and the value that EGD places on RAM.

Requests:

(a) Please provide a detailed explanation of how EGD utilizes the RAM feature in relation to its individual contract profile and gas management strategy.
(b) For the period starting November, 2004, please provide a table showing all assignments of Mainline FT by month for transportation from EGD that exceeds 4,000 GJ/D. Please include: assignee, receipt point, delivery point, Toll and volume since November 2004.
(c) For all assignments in (b) above, please provide any costs invoiced either from assignee to EGD or from EGD to the assignee as a result of the assignments in $/GJ.
(d) For all assignments in (b) above, please provide any other consideration (such as discounted storage, delivered gas, or any other consideration) provided either from assignee to EGD or from EGD to the assignee as a result of the assignment in $/GJs.
(e) Please provide details on any arrangements EGD has entered into with third Parties for purposes of managing EGD’s transportation contracts and/or transportation requirements on TransCanada for 2012. Please also provide a forecast for any additional arrangements EGD plans to enter into for these arrangements.
(f) Based on TransCanada’s Mainline Transportation Invoices to EGD please provide on a monthly basis, EGD’s Total Interruptible Transportation charges (before RAM Credits) and the Net Interruptible charges (after RAM Credits) for Mainline service from November 2004 to March 2012.
(g) Please provide the quantities of FT and STS not utilized which account for the RAM dollar figures outlined in (f) above. Please provide the quantities and transportation paths, by month, from November 2004 to March 2012.

(h) For the years 2004 through 2012, please provide a detailed explanation of how the value derived from the assignment of Mainline capacity is credited in whole or in part to EGD's rate payers. If any portion of revenue derived through the assignment of Mainline capacity is retained by EGD shareholders, please identify the mechanism and dollar amounts.
(i) In each year from 2004 through 2011, what was the total amount received by EGD through RAM and what was the share credited to EGD's customers.
(j) Please provide a forecast for the period 2012 through 2017 of the total amount expected to be received by EGD through RAM and the share of that amount expected to be credited to EGD's customers.
(k) Prior to the implementation of RAM, please describe how EGD mitigated its unutilized demand charges.

Response:

a) All TransCanada Mainline capacity is contracted by EGDI to meet the needs of its utility customers. Since the inception of RAM in 2004 EGDI has kept its long haul Mainline capacity flowing at a 100% load factor. As such EGDI has never accrued any long haul credits related to the RAM service. During periods of reduced demand and restrictions, typically during the summer months, EGDI temporarily releases parts of its long haul Mainline capacity to third parties. Tied to each release is an exchange through which EGDI delivers gas at Empress and receives an equivalent volume of gas at Dawn.

   In November of 2007 TransCanada attached the RAM feature to STS contracts. Enbridge operates its STS contracts dependent on utility demand. RAM credits are accumulated during the winter period when the utility does not require maximum STS flow. These credits are then used to offset charges related to the use of IT for managing storage balances. The ratepayer receives 100% of this benefit in the form of lower transportation charges. Any remaining RAM credits are optimized in the secondary market and shared between the ratepayer and shareholder.

b) EGDI objects to filing the information requested on the ground that it is commercially sensitive information that EGDI has consistently treated as confidential and the disclosure of which could reasonably be expect to result in a material loss to the company or its customers. EGDI would require the consent of its counterparties to provide this information.

c) Please see the response to (b) above.

d) Please see the response to (b) above.

e) Please see the response to (b) above.

f) As explained in the response to (a) above EGDI has never accrued any long haul credits related to the RAM service. Please see the table below for EGDI IT charges and net IT charges from January 2007 to March 2012.

Enbridge Invoice Summary: TransCanada Mainline Interruptible Transportation			
Month	Total Interruptible Transportation Charges ($ 000)	Applied RAM Credits ($ 000)	Net Interruptible Transportation Charges ($ 000)
Jan-07	$77.3	$0.0	$77.3
Feb-07	$13.1	$0.0	$13.1
Mar-07	$217.8	$0.0	$217.8
Apr-07	$102.8	$0.0	$102.8
May-07	$262.3	$0.0	$262.3
Jun-07	$313.7	$0.0	$313.7
Jul-07	$256.4	$0.0	$256.4
Aug-07	$246.2	$0.0	$246.2
Sep-07	$348.9	$0.0	$348.9
Oct-07	$259.7	$0.0	$259.7
Nov-07	$453.3	$418.2	$35.1
Dec-07	$118.5	$111.0	$7.5
Jan-08	$337.0	$315.0	$22.0
Feb-08	$241.7	$225.6	$16.0
Mar-08	$425.2	$395.7	$29.4
Apr-08	$253.5	$239.1	$14.4
May-08	$341.6	$0.0	$341.6
Jun-08	$439.3	$0.0	$439.3
Jul-08	$336.8	$0.0	$336.8
Aug-08	$292.0	$0.0	$292.0
Sep-08	$326.6	$0.0	$326.6
Oct-08	$142.9	$0.0	$142.9
Nov-08	$424.6	$390.4	$34.2
Dec-08	$340.2	$283.2	$57.0
Jan-09	$142.3	$132.1	$10.3
Feb-09	$253.2	$140.3	$112.9
Mar-09	$333.9	$304.9	$29.0
Apr-09	$269.9	$157.4	$112.5
May-09	$131.1	$0.0	$131.1
Jun-09	$276.3	$0.0	$276.3
Jul-09	$130.4	$0.0	$130.4
Aug-09	$164.8	$0.0	$164.8
Sep-09	$311.9	$0.0	$311.9
Oct-09	$47.8	$0.0	$47.8
Nov-09	$439.2	$407.8	$31.4
Dec-09	$166.9	$154.9	$12.0
Jan-10	$194.7	$186.6	$8.1
Feb-10	$224.7	$215.5	$9.1

Mar-10	$493.1	$472.4	$20.7
Apr-10	$272.7	$250.1	$22.6
May-10	$173.4	$0.0	$173.4
Jun-10	$151.6	$0.0	$151.6
Jul-10	$112.6	$0.0	$112.6
Aug-10	$173.4	$0.0	$173.4
Sep-10	$222.1	$0.0	$222.1
Oct-10	$4.5	$0.0	$4.5
Nov-10	$431.0	$414.3	$16.7
Dec-10	$217.2	$208.8	$8.4
Jan-11	$171.3	$164.8	$6.5
Feb-11	$169.7	$163.1	$6.6
Mar-11	$470.7	$442.8	$28.0
Apr-11	$338.7	$316.5	$22.2
May-11	$172.7	$0.0	$172.7
Jun-11	$91.5	$0.0	$91.5
Jul-11	$177.6	$0.0	$177.6
Aug-11	$236.5	$0.0	$236.5
Sep-11	$148.3	$0.0	$148.3
Oct-11	$55.8	$0.0	$55.8
Nov-11	$647.3	$608.8	$38.5
Dec-11	$651.4	$612.8	$38.6
Jan-12	$402.4	$375.9	$26.6
Feb-12	$586.7	$540.7	$46.0
Mar-12	$424.0	$398.9	$25.2

g) EGDI declines to provide the requested information on the grounds that the request is unreasonable. The time and effort involved in the preparation of a response are not warranted by the probative value of the result. In an effort to assist parties in understanding EGDI's utilization of STS and the associated RAM credits please see response to (h) above and the table below.

As discussed in (a) EGDI has flowed its long haul Mainline capacity at a 100% load factor and as a result has not accrued any long haul credits related to the RAM service. EGDI accumulates and optimizes RAM credits related to STS each winter. EGDI has done so since the inception of STS-RAM in November of 2007. Please see the table below for unutilized STS capacity from November 2007 to March 2012 for the EGDI CDA and EGDI EDA.

Summary of Enbridge Unutilized STS Capacity		
Month	**Parkway to Enbridge CDA (PJ)**	**Parkway to Enbridge EDA (PJ)**
Nov-07	6.7	1.6
Dec-07	4.4	1.2

Jan-08	4.5	1.4
Feb-08	3.4	0.9
Mar-08	5.8	1.6
Apr-08	3.7	0.7
May-08	-	-
Jun-08	-	-
Jul-08	-	-
Aug-08	-	-
Sep-08	-	-
Oct-08	-	-
Nov-08	5.5	1.2
Dec-08	4.0	0.8
Jan-09	0.8	0.7
Feb-09	2.7	0.9
Mar-09	5.5	1.3
Apr-09	3.0	0.6
May-09	-	-
Jun-09	-	-
Jul-09	-	-
Aug-09	-	-
Sep-09	-	-
Oct-09	-	-
Nov-09	6.9	1.9
Dec-09	2.2	1.0
Jan-10	1.9	0.8
Feb-10	2.8	0.8
Mar-10	6.6	1.6
Apr-10	4.1	0.6
May-10	-	-
Jun-10	-	-
Jul-10	-	-
Aug-10	-	-
Sep-10	-	-
Oct-10	-	-
Nov-10	5.6	1.4
Dec-10	1.8	1.1
Jan-11	1.5	0.8
Feb-11	1.9	0.9
Mar-11	3.2	1.4
Apr-11	3.2	0.7
May-11	-	-
Jun-11	-	-

Jul-11	-	-
Aug-11	-	-
Sep-11	-	-
Oct-11	-	-
Nov-11	7.1	1.0
Dec-11	6.3	1.4
Jan-12	3.8	0.8
Feb-12	5.3	1.2
Mar-12	4.8	0.7

h) RAM credits are first used to offset the cost of IT service incurred by the utility. Ratepayers receive 100% of the RAM benefit in this case through lower transportation charges. In addition, EGDI currently guarantees $8 million of transportation optimization revenue and storage optimization revenue, in aggregate, to its ratepayers. The optimization activities and associated dollar amounts underpinning this guarantee were not and have not been explicitly identified. This guarantee is credited to the revenue requirement prior to calculating the rates EGDI charges its customers. In the event that optimization revenue is greater than the guarantee, EGDI shares these amounts with its ratepayers. Currently transportation optimization revenues are shared 75% to the rate payer and 25% to the shareholder. For an explanation of how EGDI utilizes the RAM feature please see response to (a) above.

i) Please refer to the response to (a) above for a description of how EGDI utilizes the RAM attribute and the response to (h) above for an explanation of how EGDI shares optimization revenues. The table below shows RAM credits, the amount of RAM credits optimized and the optimization revenue shared with the ratepayer.

Year	**Total RAM Credits (000's)**	**RAM Credit $'s Optimized (000's)**	**TS Revenue (000's)**	**Ratepayer Benefit from RAM Credits (100%) (000's)**	**Ratepayer Share of Optimization Revenue (75%) (000's)**	**Total Ratepayer Benefit (000's)**
	a	**b**	**c**	**d=a-b**	**e=0.75xc**	**d+e**
2007	$529.1	$333.2	$75.0	$195.9	$56.2	$252.1
2008	$1,849.0	$1,155.9	$406.3	$693.1	$304.7	$997.8
2009	$1,297.3	$1,125.5	$476.3	$171.8	$357.2	$529.1
2010	$1,747.8	$1,546.1	$489.0	$201.7	$366.7	$568.4
2011	$2,308.9	$2,105.7	$819.4	$203.1	$614.5	$817.7

j) EGDI does not forecast specific elements of or revenues related to its optimization activities. Please see response to (h) above.

k) EGDI has always attempted to eliminate or minimize unutilized demand charges on long haul by using storage services and maintaining sufficient diversity in its transportation portfolio.

Prior to the implementation of RAM any unutilized demand charges were mitigated through optimization activities. In rare instances, if unutilized demand charges were forecast and incurred, they would have been recovered from the ratepayer.

6. Reference:

(i) Written Evidence of the MAS, page 33, lines 18-19.

Preamble: In Reference (i) MAS states: "Retaining the status quo for RAM now is more important than ever to provide Mainline shippers market and service stability."

TransCanada seeks to obtain more information on EGD's desire to retain RAM and the impact on EGD's ratepayer.

Requests:

(a) Please provide EGD's actual RAM revenue and exchange revenue in 2011.
(b) Please provide EGD's forecast RAM revenue and exchange revenue in 2012.
(c) Has EGD provided any forecast of RAM revenue to any other regulators for2013? If so, how much is EGD forecasting for RAM revenue and exchange revenue in 2013?
(d) If the response to (c) is yes, please provide that forecast and any filed documents which pertain to EGD's use of RAM.
(e) Given the information in (b) and (c) above, please describe how EGD's rate payer and shareholder will benefit if RAM is continued, relative to if RAM is discontinued.

Response:

a) EGDI optimized $2.1 million of RAM credits in 2011, generating approximately $0.82 million in exchange revenue. Please refer to the response to 1.5(i).

b) Please see response to 1.5(j).

c) No. Please see response to 1.5(j).

d) Please see response to (c).

e) EGDI utilizes the RAM credits it generates to offset any IT costs it incurs. 100% of these IT savings accrue to the ratepayer. Any unutilized RAM credits are then optimized and revenues generated are shared between the ratepayer and shareholder.

   If RAM is continued EGDI's ratepayer and share holder would benefit through the potential optimization of EGDI's capacity on the Mainline. If RAM is discontinued the potential for EGDI to optimize its capacity on the Mainline could be reduced. In the event this occurs the optimization revenues could potentially be reduced as well.

   Please refer to the response to 5(a) for a discussion of how EGDI utilizes the RAM attribute.

CME INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Reference: Exhibit C1, Tab 4, Schedule 1

Does EGD take any steps to optimize the value of its utility storage? If so, then please list the services that EGD provides to optimize the value of its storage capacity and the revenues that it has derived from the provision of such services for each of the years 2007 to 2012 to date and indicate whether the full amount of any such revenues have been credited to the TSDA in each of the years in which such revenues were received.

RESPONSE

For a description of Transactional Services please see the response to Board Staff Interrogatory #1 at Exhibit I, Issue C6, Schedule 1.1.

For 2007 – 2011 historical and 2012 estimate of Transactional Services revenue please see the response to Board Staff Interrogatory #2 Exhibit I, Issue C6, Schedule 1.2.

Witnesses: V. Krauchek
J. Sarnovsky
D. Small

CCC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C1/T4/S1/p. 1

The evidence states that since the TS function was first established in 1997 Enbridge has succeeded in meeting the gross margin thresholds and ratepayer guarantees as set out in the TS sharing methodology. Please provide the forecast and actual levels of TS revenue since 1997. Please specify the amounts allocated to ratepayers and shareholders. Please include gross and net amounts.

RESPONSE

Please see the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2, which provides actual Transactional Services revenue for Fiscal years 2007 to 2011, as well as a forecast for Fiscal 2012.

Witnesses: V. Krauchek
J. Sarnovsky

CCC INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C1/T4/S1/p. 1

The evidence states that in 2011 the TS storage revenue is expected to be $2.7 million. What was the actual amount? To the extent it differs from the $2.7 million forecast what is the reason for the variance? Please describe how the amount was calculated. What is the 2012 revenue year to date?

RESPONSE

The actual amount of 2011 TS Storage Revenue is $3.5 million. Please see the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2. The difference between the actual and the forecast amount is primarily due to the inclusion of $0.7 million in the actual pertaining to Rider H which relates to Enhanced Title Transfers.

A forecast of the 2012 TS revenue can be found in the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2.

Witnesses: V. Krauchek
J. Sarnovsky

CCC INTERROGATORY #3

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C1/T4/S1/p. 2

The evidence states that the 2011 estimate for TS transportation revenue is expected to be $15 million. What was the actual amount. To the extent it differs from the $15 million please explain the variance. Please explain how the amount was calculated. What is the 2012 revenue year to date?

RESPONSE

The actual amount of 2011 TS Transportation Revenue is $16.3 million. Please see the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2. The forecast was based upon the transactional service deals entered into at the time the forecast was prepared. The difference between the actual and the forecast amount is due to the inclusion of additional transactional services deals.

A forecast of the 2012 TS revenue can be found in response to Board Staff Interrogatory #2 Issue C6, Schedule 1.2.

Witnesses: V. Krauchek
J. Sarnovsky

CCC INTERROGATORY #4

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C1/T4/S1/p. 3

Please explain, in detail, how EGD generates TS revenue through the use of TCPL's FT-RAM service. Please provide several examples.

RESPONSE

Please see the response to Energy Probe Interrogatory #2 at Exhibit I, Issue DV1, Schedule 7.2.

Witnesses: V. Krauchek
J. Sarnovsky

CCC INTERROGATORY #5

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C1/T4/S1/p. 3

What is the basis for the $6 million revenue guarantee? Please include all assumptions and calculations used to arrive at that amount. What is the 2012 and 2013 TS revenue forecast? What are the associated costs?

RESPONSE

The Company is not proposing a $6.0 million guarantee, but rather a threshold amount such that if TS revenues were not to achieve the $6.0 million amount proposed for inclusion in rates, then the Company would have the ability to recover the shortfall from ratepayers through the TSDA. Please see the response to Energy Probe Interrogatory #2 at Exhibit I, Issue C6, Schedule 7.2.

An update of the 2012 TS revenue forecast was provided in the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2.

Witnesses: V. Krauchek
J. Sarnovsky

CCC INTERROGATORY #6

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C1/T4/S1/p. 4

What is the rationale (other than it has previously been in place) for the different sharing proportions for TS related storage and transportation revenue (90:10 vs. 75:25)?

RESPONSE

In the NGEIR Decision with Reasons (EB-2005-0551 dated Nov. 7, 2006, on pages 98 through 112) the Board indicated that the then – current 25% incentive for storage-related TS revenues was too large and that a Company share of 10% would be sufficient, resulting in a 90/10 sharing of storage related TS deals.

At that time, the Board did not change its 2006 Decision related to the 75/25 sharing mechanism on the balance of Enbridge's TS deals (transportation related).

The Company is not proposing any changes to the NGEIR Decision and is not aware of any market development that would justify any change.

Witnesses: V. Krauchek
J. Sarnovsky

CCC INTERROGATORY #7

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: C3/T5/S1

What is the current status of the NGV program? What are EGD's ongoing plans for the program? Why is the program continuing if it is not generating a revenue sufficiency? Please provide the rate of return/ deficiency/sufficiency analysis for each year 2007 to 2012?

RESPONSE

For the current status and ongoing plan for EGD's NGV program, please see the response to Board Staff Interrogatory #3 at Exhibit I, Issue C1, Schedule 1.3.

Please see the table below for return/deficiency/sufficiency analysis for each year 2007 to 2012.

	2013	2012	2011	2010	2009	2008	2007
NGV RATE OF RETURN	-5.10%	3.86%	3.73%	1.89%	0.41%	-0.10%	0.27%
Pre Tax Sufficiency / (Deficiency)	(476,765)	(103,801)	(126,296)	(253,858)	(318,619)	(554,992)	(709,400)

Witnesses: F. Ahmad
K. Culbert
M. Tremyane

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Exhibit C1, Tab 4, Schedule 1

a) Please update the 2011 amount noted in paragraph 4 to reflect actual 2011 TS storage revenue.

b) Please update the 2011 amount noted in paragraph 6 to reflect actual 2011 transportation revenues.

c) Please confirm that the proposal discussed in paragraph 11 is asymmetric in that ratepayers pay 100% of any shortfall relative to the $6 million included in rates, while receiving only 90% of any overage on storage revenues and 75% on transportation revenues.

d) Please provide the most recent year-to-date TS-related storage and transportation revenues for 2012.

RESPONSE

a), b) and d) Please see the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2.

c) That is correct. Please see the response to Energy Probe Interrogatory #2 at Exhibit I, Issue C6, Schedule 7.2, part b)

Witnesses: V. Krauchek
J. Sarnovsky

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

C- Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Exhibit C3, Tab 4, Schedule 1 &
Exhibit C1, Tab 4, Schedule 1

a) Please explain the Fiscal 2007 heading on the table in Exhibit C3, Tab 4, Schedule 1.

b) The total transactional services forecast shown in Exhibit C3, Tab 4, Schedule 1 is $6 million, but there is no breakdown of this amount between TS-related storage and transportation revenue. The proposed sharing arrangement for these revenues are different, as noted on page 4 of Exhibit C1, Tab 4, Schedule 1. Please breakdown the $6 million into the two components so that parties can see the base amounts above which the different sharing percentages would apply.

RESPONSE

a) The heading should read Fiscal 2013. The Exhibit has been updated.

b) For the purposes of designing rates the Company assumes that the $6 million will be split 50/50 between Storage Optimization and Transportation Optimization. Therefore, the Company has assumed for forecast purposes that it will achieve $3.33 million in storage revenue and $4 million in transportation revenue ((3.33 X 90%) + (4.0 x 75%)). However under the current methodology there is no distinction between actual and forecast revenue by transaction type. For every dollar of storage revenue generated 90 cents is identified as customer revenue and for every dollar of transportation revenue generated 75 cents is identified as customer revenue. When the sum of these two amounts equals the amount included in rates then, any excess amount goes to the Transactional Services Deferral Account ("TSDA") for future disposition. For 2013, the Company is

Witnesses: V. Krauchek
J. Sarnovsky

proposing that if in the event the customer generated dollars do not exceed the $6 million included in rates then the Company should be able to capture the underage in the TSDA and collect that amount from ratepayers.

Witnesses: V. Krauchek
J. Sarnovsky

FRPO INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: Exhibit D1, Tab 13, Schedule 1, Page 2

EGD states that the Gas Supply group has responsibility for Transactional Services.

a. Are any of the individuals involved in the sale of Transactional Services also involved in the sale of storage services from EGD's non-utility ("unregulated") storage operation? If so, please explain.

b. How are ex-franchise storage service transactions that are underpinned by utility storage assets (i.e. Transactional Services) kept separate from ex-franchise storage service transactions that are underpinned by non-utility storage assets?

c. Beyond the delivery and/or receipt point of Tecumseh, what are the points at which EGD offers exchange points for non-utility storage transactions (for example Parkway)?

    i. How does EGD non-utility effect transportation to and from Tecumseh to those locations?
    ii. What assets or transportation rights does EGD use to effect these transactions?
    iii. How is the utility compensated for any assets owned by or rights contracted by the utility?

RESPONSE

a. No

Witnesses: K. Culbert
V. Krauchek
B. Pilon
J. Sarnovsky
R. Small

b. Transactional Services storage deals are related to available utility assets only. TS personnel do not have access to information regarding the availability of non-utility storage assets and as such, at no time is the execution of a TS storage deal a function of non-utility storage balances. This separation of business units includes the gas management system (OpenLink) which records all TS storage transactions and which restricts access to its databases to authorized employees only (there are no individuals involved in the sale of unregulated storage with access to this system).

c. EGD does not offer unregulated storage receipt/delivery beyond the Tecumseh custody inter-connect points.
   i. N/A
   ii. N/A
   iii. N/A

Witnesses: K. Culbert
V. Krauchek
B. Pilon
J. Sarnovsky
R. Small

FRPO INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

Ref: EB-2005-0551 (NGEIR Decision), p.102.

In the NGEIR Decision, the Board found that EGD's retention of 25% of the margin on storage-related Transactional Services was "excessive", and required EGD to change the sharing formula to 90/10. Since EGD ratepayers pay all of the costs of the transmission assets supporting transportation-related transactional services, please explain why the Board should continue to allow EGD to retain 25% of the margin on these transactions.

RESPONSE

The sharing mechanisms in place for storage and transportation related Transactional Services have been approved by the Board. EGD is not considering nor proposing any changes to the current sharing mechanisms. The Company will continue to abide by the Board's prior decisions which hold the sharing formulas as 90/10 for storage and 75/25 for transportation (ratepayer/shareholder split in both cases).

Please also refer to Exhibit I, Issue C6, Schedule 5.6 for a further response on this issue.

Witnesses: V. Krauchek
J. Sarnovsky

VECC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 6: Is the proposal for the treatment and sharing of Transactional Services revenues, and the forecast of those revenues, appropriate?

References: Exhibit C1 Tab 4 Schedule 1 Page 5
Exhibit C3 Tab 4 Schedule 1

a) Please update the 2011 TS revenues.

b) Please confirm that the proposed reduction from $8 million to $6 million in the TS revenue embedded in rates will, when combined with 90% sharing of overage on storage revenues and 75% on transportation revenues, result in a reduction in revenue offsets for ratepayers.

c) Please breakdown the $6 million into Storage and Transportation components.

d) Provide a calculation of the shareholder and ratepayer revenues based on the current formula and proposed formula using 2011 actuals and assuming no change in O&M.

e) Please provide the year-to-date TS-related storage and transportation revenues for 2012.

RESPONSE

a) and d) Please see the attached table.

b) The table provided in response to part a) and part d) provides an update for the 2011 Actual TS Revenues, as well as the amount to be cleared to customers via the 2011 TSDA. The schedule demonstrates that regardless of whether or not $8 million or $6 million in TS revenue was embedded in rates in Fiscal 2011 the customer would have received the same amount of TS revenue. Item 2, Column 4 and Item 6, Column 4 identifies the rate payer share of the 2011 Transactional

Witnesses: V. Krauchek
J. Sarnovsky

Services revenue to be $15.4 million regardless of the amount embedded in rates. Assuming the current formula, the customer received $8 million in rates and an additional $7.4 million via the TSDA for a total of $15.4 million. Under the proposed formula the customer would receive $6 million in rates and an additional $9.4 million via the TSDA for a total of $15.4 million. Therefore, the assumption in question b) is incorrect.

c) Please see the response to Energy Probe Interrogatory #2 at Exhibit I, Issue C6, Schedule 7.2, part b).

e) Please see the response to Board Staff Interrogatory #2 at Exhibit I, Issue C6, Schedule 1.2.

Witnesses: V. Krauchek
J. Sarnovsky

Table 1

Item #	Column 1	Column 2	Column 3	Column 4
	2011 - Actual	Storage Optimization $(000's)	Pipeline Optimization $(000's)	
1.	Net Revenue	3,464.5	16,318.5	19,783.0
	Rate Payer - %	90.00%	75.00%	
2.	Rate Payer - $(000's)	3,118.1	12,238.9	15,356.9
3.	**Amount Included in Rates**			**(8,000.0)**
4.	**Amount Transferred to 2011 TSDA**			7,356.9
	2011	Storage Optimization $(000's)	Pipeline Optimization $(000's)	
5.	Net Revenue	3,464.5	16,318.5	19,783.0
	Rate Payer - %	90.00%	75.00%	
6.	Rate Payer - $(000's)	3,118.1	12,238.9	15,356.9
7.	**Amount Included in Rates**			**(6,000.0)**
8.	**Amount Transferred to TSDA assuming lower amount embedded in rates**			9,356.9

BOARD STAFF INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

Ref: Ex. C1 /Tab 5/ Sch 1 / para 3

Please advise as to whether there are any changes proposed for the Direct Purchase Administration charge or any of the other service charges and/or late payment penalties.

RESPONSE

There are no changes proposed to any of these charges/rates.

Witnesses: S. McGill
M. Torriano

CCC INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

Ref: C3/T3/S1

Please re-cast "Details of Other Revenue" to include 2007 Board approved and actual amounts for 2007-2011.

RESPONSE

Please see the following Table for "Details of Other Revenue", including 2007 Board approved and 2007-2011 actual amounts.

Details of Utility Other Revenue

($millions)

Item No.		Col.1 2007 Board Approved	Col.2 2007 Actual	Col.3 2008 Actual	Col.4 2009 Actual	Col.5 2010 Actual	Col.6 2011 Actual	Col.7 2012 Bridge Year	Col.8 2013 Test Year
1.1	Service Charges & DPAC	11.9	12.3	12.4	12.7	13.0	13.2	12.7	12.9
1.2	Rental Revenue - NGV Program	1.3	1.1	0.9	0.6	0.8	0.5	0.4	0.8
1.3	Late Payment Penalties	8.0	11.1	12.0	14.0	13.1	13.2	13.2	12.9
1.4	Dow Moore Recovery	0.3	0.2	0.2	0.2	0.2	0.3	0.3	0.3
1.5	NGV Merchandising Revenue (net)	0.1	0.1	-	-	-	0.1	-	-
1.6	Transactional Services (net)	8.0	8.0	8.0	8.0	8.0	8.0	8.0	6.0
1.7	Ontario Power Authority Program Revenue		-	3.6	5.9	11.7	-	-	-
1.8	Miscellaneous	0.1	1.4	0.7	1.6	1.6	0.7	0.1	0.7
1.9	Open Bill Revenue	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
2.0	Total Other Revenue	35.1	39.6	43.2	48.4	53.8	41.4	40.1	39.0

Witnesses: R. Lei
S. Qian

CCC INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

Ref: C3/T3/S1

Please explain, in detail, how EGD forecasts late payment penalty revenue.

RESPONSE

The Late Payment Penalties ("LPP") forecast is based on management estimate informed by a regression model. The model regresses LPP against residential gas prices, degree days, and the number of unlocked customers.

Please see the response to VECC Interrogatory, at Exhibit I, Issue C7, Schedule 20.1, part b).

Witness: K. Lakatos-Hayward
S. McGill

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

Ref: Exhibit C1, Tab 5, Schedule 1

a) Please provide a table in the same level of detail as that shown in Table 2 that shows the actual revenues for 2007 through 2011 and the forecast for 2012 and 2013.

b) Please expand Table 3 to include actual data for 2007 through 2010 and update the 2011 figure to reflect actual revenues, along with the forecast for 2012 and 2013.

c) Is EGD forecasting an increase in the cost of gas in 2013 relative to 2012 and in 2012 relative to 2011? How has the change in the cost of gas forecast been reflected in the late payment penalty revenues?

RESPONSE

a) Please refer to Exhibit I, Issue C7, Schedule 20.1, Table 1.

b) Please refer to Exhibit I, Issue C7, Schedule 20.1, Table 2.

c) The Company originally forecast an increase in the cost of gas in the 2012 Estimate and 2013 Budget for Late Payment Penalty revenues as filed. For further information on gas costs please see the response to CME Interrogatory, at Exhibit I, Issue D1, Schedule 4.1. The LPP forecast is informed by a regression model, and gas cost is an input to the model. Also, please see the Company's response to VECC Interrogatory, at Exhibit I, Issue C7, Schedule 20.1, part b).

Witnesses: S. McGill
M. Torriano

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

Ref: Exhibit C3, Tab 3, Schedule 1 &
Exhibit C3, Tab 5, Schedule 1

Please reconcile the NGV related revenue shown in Exhibit C3, Tab 3, Schedule 1 of $0.8 million with the $1.092 million shown in Exhibit C3, Tab 5, Schedule 1.

RESPONSE

Please see Table below for NGV revenue reconciliation.

Table A
NGV Reconciling Items

	Exhibit C3,T5,S1,P1 ($000's)	Exhibit C3,T3,S1,P1 (Col. 1, Item No. 1.2) ($000's)	Variance ($000's)	
Gas Distribution Margin	781.8	-	781.8	a)
Other Revenue / Rental Revenue - NGV Program	311.0	787.8	(476.8)	b)
Total Revenue	1,092.8	787.8	305.0	

a) Variance:

Rate 1 - Residential	22.6
Rate 6 - Commercial General	680.5
Rate 9 - NGV	43.1
Rate 110 & 115 - Large Volume Contract	35.6
Gas Distribution Margin	781.8

b) NGV revenue imputation to equate the program's overall return to the required regulated return.

Witnesses: F. Ahmad
K. Culbert
R. Lei
S. Qian

JUST ENERGY INTERROGATORY #1

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

In the Rate Handbook Enbridge indicates the proposed Rider A and Rider B charges will be:

> *MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:*
> *Fixed Charge $75.00 per month*
> *Account Charge $0.21 per month per account*

a) Please fully explain the reason for the proposed increase from $0.19 per month per account to $0.21 per month per account for the DPAC Account charge.

b) Please provide the back-up to support the proposed DPAC Account Charge increase

c) Please indicate if any fee change is proposed for the ABC charge.

RESPONSE

a) and b) Enbridge is proposing no changes to its DPAC account charge for 2013. The account charge is currently $0.21 per month per account that was approved in EB-2009-0172 (2010 Test Year).

c) The Company is proposing no changes to the ABC Charge for 2013.

Witnesses: J. Collier
K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #20

INTERROGATORY

C - Operating Revenue
Issue 7: Is Enbridge's forecast of other service and late payment penalty revenues, including the methodologies used to cost and price those services, appropriate?

Reference: Exhibit C1 Tab 5 Schedule 1 Table 2

a) Please provide a table that shows the actual revenues for 2007 through 2011 and the forecast for 2012 and 2013.

b) What is the relationship between Late Payment charges/revenue and cost of gas?

c) Please provide a Table that shows average gas costs and LP revenues from 2007-2013F.

RESPONSE

a) Please see the table below.

Table 1
Other Service Revenues
2007-2013

Line No.	Particulars ($ 000's)	Actual 2007 (a)	Actual 2008 (b)	Actual 2009 (c)	Actual 2010 (d)	Actual 2011 (e)	(1) Estimate 2012 (f)	(1) Budget 2013 (g)
1.1	New Account Charge	$ 5,755	$ 5,358	$ 5,809	$ 5,270	$ 5,397	$ 5,471	$ 5,576
1.2	Statement of Account & Lawyer Letters Charge	187	37	36	22	13	51	52
1.3	Cheques Returned Non-Negotiable Charge	237	232	191	176	172	156	159
1.4	Gas Termination Charge for Collection	2,006	2,130	2,147	2,323	2,344	2,588	2,638
1.	Total Credit to Customer Support O&M	$ 8,185	$ 7,757	$ 8,183	$ 7,791	$ 7,926	$ 8,266	$ 8,425
2.1	Safety Inspection Revenue	415	642	385	412	453	474	489
2.2	Meter Testing Revenue	546	581	560	716	900	789	813
2.3	Street Service Alteration Revenue	934	1,177	901	836	972	909	936
2.		$ 1,895	$ 2,400	$ 1,846	$ 1,964	$ 2,325	$ 2,172	$ 2,238
3.	Total	$ 10,080	$ 10,157	$ 10,029	$ 9,755	$ 10,251	$ 10,438	$ 10,663
4.	DPAC	2,181	2,214	2,628	3,269	3,014	2,254	2,125
5.	Total Service Charge & DPAC	$ 12,261	$ 12,371	$ 12,657	$ 13,024	$ 13,265	$ 12,692	$ 12,788

(1): 2012 and 2013 figures are as filed in EB-2011-0354, Exhibit C1, Tab 5, Sch. 1, Page 2

Witnesses: S. McGill
M. Torriano

b) The Late Payment Penalties ("LPP") forecast is based on management estimate informed by a regression model. The model regresses LPP on residential gas prices, degree days, and the number of unlocked customers. Although residential gas prices are included in the model as an explanatory variable, degree days and the number of unlocked customers have a stronger correlation with LPP.

c) Please see the table below. The figures for 2013 Budget are as originally filed for consistency. For further information on gas costs please see the response to CME Interrogatory, at Exhibit I, Issue D1, Schedule 4.1.

The 2012 and 2013 LPP revenue figures include the estimated impact of LPP revenue lost due to the implementation of the new Customer Service Rules. The 2012 partial-year estimated impact is $0.35 million, and the 2013 estimated impact is $0.5 million. The Company's experience to-date in 2012 would indicate that the LPP revenue lost due to the implementation of Customer Service Rules will be greater than estimated at the time the 2013 Budget was developed.

Table 2
Late Payment Penalty Revenues and Weather Normalized Gas Costs
2007-2013

Line No.	Particulars ($millions)	Actual 2007 (a)	Actual 2008 (b)	Actual 2009 (c)	Actual 2010 (d)	Actual 2011 (e)	(1) (2) Estimate 2012 (f)	(1) (2) Budget 2013 (g)
1	Late Payment Penalty Revenues	11.1	12.0	14.0	13.1	13.2	13.2	12.9
2	Gas Costs (weather normalized)	2,047.7	2,137.8	1,862.6	1,450.7	1,383.7	1,515.5	1,548.6

(1): Late Payment Penalty Revenue figures for 2012 and 2013 are as filed in EB-2011-0354, Exhibit C1, Tab 5, Sch. 1, Table 3
(2): Normalized Gas Costs for 2012 and 2013 are as filed in EB-2011-0354, Exhibit D1, Tab 1, Sch. 1, Table 1

Witnesses: S. McGill
M. Torriano