BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D3 /Tab 2/ Sch 3 / page 1

The table provides detail of the O&M expenses by "Cost Type" for 2012 and 2013.

Please provide a table by "Cost Type" for the years 2007 through 2013.

RESPONSE

Please refer to the table below by "Cost Type" for the years 2007 Actual through 2013 Budget:

Witnesses: S. Kancharla
R. Lei

Witnesses: S. Kancharla
R. Lei

Enbridge Gas Distribution
Operating and Maintenance Expense by Cost Type
From 2007 Actual to 2013 Test Year

Line No.	Particulars ($000's)	Budget 2013	Estimate 2012	Actual 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007
1.	Salaries and Wages	$ 170,856	$ 160,672	$ 141,477	$ 133,797	$ 125,079	$ 127,001	$ 127,092
2.	Benefits	30,452	25,941	24,263	22,864	22,770	22,047	24,390
3.	Pension	37,300	20,557	3,225	3,994	2,570	1,749	1,499
4.	Short Term Incentive Program	20,257	19,428	25,206	19,681	25,303	19,109	20,084
5.	Employee Training and Development	4,137	4,041	5,564	2,853	2,990	2,713	1,983
6.	Materials and Supplies	5,511	5,495	5,202	5,061	4,379	5,690	4,901
7.	Outside Services	78,979	77,868	63,208	60,787	55,664	51,834	50,468
8.	Regulatory Costs	7,343	5,843	4,824	5,843	5,843	5,843	8,843
9.	Consulting	9,541	6,687	5,026	6,359	3,713	4,762	2,544
10.	Repairs and Maintenance	1,961	1,946	1,387	1,746	1,976	660	2,812
11.	Fleet	9,974	9,768	9,005	8,125	8,335	9,861	9,405
12.	Rents and Leases	7,671	7,438	7,286	5,716	6,526	7,073	7,481
13.	Telecommunications	3,668	3,619	3,136	3,517	3,388	3,107	3,400
14.	Travel and Other Business Expenses	4,891	4,702	3,540	3,420	2,679	3,086	2,741
15.	Memberships	3,384	3,158	3,978	3,618	2,589	2,527	2,452
16.	Claims, Damages and Legal Fees	816	754	1,599	1,665	2,002	1,214	1,583
17.	Customer Care Service Charges (including CIS)	89,422	90,436	79,199	87,506	92,441	92,283	94,323
18.	Interest on Security Deposits	2,716	1,933	1,036	496	1,027	1,726	1,718
19.	Provision for Uncollectibles	15,172	13,700	21,542	11,500	17,831	16,662	15,205
20.	Consumers Gas Ltd Charges	-	-	-	-	-	415	362
21.	Internal Allocations and Recoveries	(25,263)	(25,130)	(25,739)	(24,780)	(23,814)	(26,141)	(20,941)
22.	Corporate Cost Allocations (including direct costs)	47,268	46,816	43,440	36,693	34,267	32,166	27,715
23.	Other	7,151	5,879	7,993	4,838	5,099	11,219	6,766
24.	Subtotal	533,209	491,549	435,394	405,299	402,655	396,606	396,825
25.	Capitalization (A&G)	(37,704)	(31,404)	(24,482)	(24,330)	(23,902)	(21,643)	(21,238)
26.	Capitalization	(69,159)	(65,273)	(55,260)	(52,629)	(50,086)	(51,769)	(53,763)
27.	Non-Utility Allocations	(3,347)	(3,220)	(4,891)	(4,066)	(1,890)	(2,071)	(2,465)
28.	Total Net Utility O&M Expense, excl. DSM, Conservation	422,999	391,652	350,761	324,274	326,778	321,124	319,359
29.	Demand Side Management Programs (DSM)	31,440	28,100	26,708	25,468	24,255	23,100	22,000
30.	Conservation Services	1,507	6,978	7,292	9,432	3,952	2,098	190
31.	Total Net Utility O&M Expense before Eliminations	455,946	426,729	384,761	359,173	354,985	346,322	341,549
32.	Regulatory Eliminations							
33.	To eliminate Corporate Cost Allocations above RCAM	(15,124)	(16,610)	(16,725)	(12,428)	(13,100)	(13,066)	(9,615)
34.	To eliminate Old CIS fees above Customer Care settlement agreement	-	-	-	-	(4,900)	(9,811)	(9,943)
35.	To eliminate Conservation Services and Overheads	(2,462)	(7,919)	(7,292)	-	-	-	-
36.	Incremental O&M Allocated to Unregulated Storage	(233)	-	(233)	-	-	-	-
37.	Total Eliminations	(17,820)	(24,529)	(24,250)	(12,428)	(18,000)	(22,877)	(19,558)
38.	Total Net Utility O&M Expense	$ 438,127	$ 402,200	$ 360,511	$ 346,746	$ 336,986	$ 323,446	$ 321,990

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D1
Schedule 1.1
Page 2 of 2

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D3 /Tab 2/ Sch 1 / page 2

With respect to the Depreciation expense, there is an increase in 2013 vs. 2012 of $10.7 million.

What is the amount of the increase in depreciation expense in 2013 if the old methodology had been continued into 2013?

RESPONSE

The 2013 depreciation expense under the old methodology would be $308.3 million as shown at Exhibit D1, Tab 5, Schedule 1, page 3. The increase in depreciation expense would be $16.7 million if the old methodology had been continued into 2013.

Witnesses: L. Au
D. Kelly

BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p1/Table 1

'Customer Care Service Charges' were approved in Board proceeding EB-2011-0226 via Settlement Agreement, which set customer care as $89.4 for 2013.

a) Please create 'Table 1A' similar to Table 1 by adding additional columns for historical actuals for 2010, 2009, 2008, and 2007.

b) Please complete the following table with year over year percentage increase or decrease by category

Table1-B: Year to Year O&M variances

	2013 v 2012	**2012 v 2011**	**2011 v 2010**	**2010 v 2009**	**2009 v 2008**	**2008 v 2007**	**2013 v 2007**
CIS							
RCAM							
DSM							
Pension Expense							
Other O&M							
Total Net Utility O&M Expense							

c) What is the average annual increase in Total O&M across the 6-year period from 2007 to 2013?

d) Please complete the following tables, removing CC/CIS project from the Total:

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

Table1-C1: Total Net Utility O&M Expense, less CC/CIS

	Budget 2013	Forecast 2012	Historical 2011	Historical 2010	Historical 2009	Historical 2008	Historical 2007
Total Net Utility O&M Expense							

Table1-C2: Year to Year variances (less CC/CIS)

	2013 v 2012	2012 v 2011	2011 v 2010	2010 v 2009	2009 v 2008	2008 v 2007	2013 v 2007
Total Net Utility O&M Expense (less CIS)							

e) Excluding CC/CIS, what is the average annual increase in Total O&M across the 6-year period from 2007 to 2013?

f) Please explain the significant increase in Pension Expense from 2012 Forecast to 2013 Budget, i.e. from $20.6M to $27.7M. Is the entirety of this increase due to accounting change? If not, please attribute the increase separately from the accounting change and any other sources.

g) Please comment on the total increase from 2011 over 2007 (a four year period), versus the increase in 2012 over 2011, and the requested increase in 2013 over 2012. Why are the annual increases significantly higher in the most recent years versus the increase in the previous 4-year period?

h) Please comment on the average annual increase to Total O&M in the most recent two years of the table (2013 Budget and 2012 Forecast) versus the increases in the earlier years of the IR plan, and versus the average annual increase to Total O&M as per Table1-C2 above.

i) There is an expectation of cost increases for Total O&M based on observed increases to the GDP-IPI and other input and/or consumer prices indices.

Please explain the portion of the increase in O&M that is attributable to inflation and/or input cost escalation, and explain the portion of the increase to Total O&M that cannot be explained by inflation and/or input cost escalation.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

RESPONSE

a) The historical actuals for 2010, 2009, 2008, and 2007 are provided in the pre-filed evidence Ex D5/T2/S5/p5, Table 1. The following Table 1 is updated with 2011 actual.

Table 1A
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2007 Board Approved to 2013 Budget

Line No.	Categories ($ Millions)	Col. 1 Updated Budget 2013	Col. 2 Estimate 2012	Col. 3 Actual 2011	Col. 4 Actual 2010	Col. 5 Actual 2009	Col. 6 Actual 2008	Col. 7 Actual 2007	Col. 8 Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$79.2	$87.5	$87.5	$82.5	$84.4	$90.8
2.	Regulatory Cost Allocation Methodology(RCAM)	32.1	30.2	26.7	24.3	21.2	19.1	18.1	18.1
3.	Demand Side Management (DSM)	31.4	28.1	26.7	25.5	24.3	23.1	22.0	22.0
4.	Pension Expense	37.3	20.6	3.2	4.0	2.6	1.7	1.5	1.7
5.	Other O&M	247.8	232.9	224.7	205.5	201.5	197.0	196.0	193.6
6.	Total Net Utility O&M Expense	$438.1	$402.2	$360.5	$346.7	$337.0	$323.4	$322.0	$326.2

b) Table1-B is attached below:

Table 1-B: Year over Year O&M Variances

	2013 vs. 2012	2012 vs. 2011	2011 vs. 2010	2010 vs. 2009	2009 vs. 2008	2008 vs. 2007	2013 vs. 2007
CC/CIS	-1.1%	14.2%	-9.5%	0.0%	6.1%	-2.3%	6.0%
RCAM	6.4%	13.1%	10.1%	14.6%	10.8%	5.5%	77.6%
DSM	11.9%	5.2%	4.9%	5.0%	5.0%	5.0%	42.9%
Pension Expense	81.4%	537.6%	-19.3%	55.4%	47.0%	16.7%	2389.1%
Other O&M	6.4%	3.7%	9.3%	2.0%	2.2%	0.5%	26.4%
Total Net Utility O&M Expense	8.9%	11.6%	4.0%	2.9%	4.2%	0.4%	36.1%

c) The average annual increase in Total O&M across the 6-year period from 2007 to 2013 is 5.3%.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

d) Table1-C1 & C2 are attached below:

Table 1-C1: Total Net Utility O&M Expense, less CC/CIS

$ Millions	Budget 2013	Forecast 2012	Historical 2011	Historical 2010	Historical 2009	Historical 2008	Historical 2007
Total Net Utility O&M Expense	348.7	311.8	281.3	259.2	249.4	241.0	237.6

Table 1-C2: Year to Year Variances (less CC/CIS)

	2013 vs. 2012	2012 vs. 2011	2011 vs. 2010	2010 vs. 2009	2009 vs. 2008	2008 vs. 2007	2013 vs. 2007
Total Net Utility O&M Expense	11.8%	10.8%	8.5%	3.9%	3.5%	1.4%	46.7%

e) Excluding CC/CIS, the average annual increase in Total O&M across the 6-year period from 2007 to 2013 is 6.7%

f) Although the basis of pension expense in 2013 is under the accrual basis, which is a change from 2012 which is under the cash basis of expense for rate regulated accounting, the increase is not attributable to the change in accounting. As evidenced in EB-2011-0354 Exhibit A2 Tab 3 Schedule 2, if EGD had stayed on the cash basis of expense in 2013, pension expense would also have increased. In fact the cash basis of expense would be larger than the accrual basis of expense. See EB-2011-0354 Exhibit A2 Tab 3 Schedule 2 for a full analysis.

The cost in 2012 is comprised solely of current service costs because that was the minimum required funding in 2012 as per pension regulations. The cost in 2013, whether under a cash basis or accrual basis, also includes an amortization of the accumulated losses (accrual basis also has interest cost and expected return on assets which generally offset each other resulting in minimal impact on total accrual cost). However, the amortization amount in 2013 is less on an accrual basis versus a cash basis because the losses are amortized over a longer period of time.

g) The level of operating expenses is driven by the business needs. Management makes decisions considering the implications for operating a safe and reliable distribution network and economic impact to all stakeholders (customers, employees and investors). Reviewing by various segments provides a better understanding of the reasons for increases in operating expenses in 2012 and 2013 compared to the increases in the previous four years.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

Table 1-A provides the segments and details. Table 1-D1 provides details comparing 2012 and 2013 average increases with previous four year average increases.

Table 1-D1: Year to Year Variances

	2013 vs. 2012	2012 vs. 2011	2011 vs. 2007 Four Year Total	(A) 2013 and 2012 Average Annual	(B) 2011 vs. 2007 Average Annual	(A)-(B)
CC/CIS	-1.1%	14.2%	-6.1%	6.5%	-1.4%	7.9%
RCAM	6.4%	13.1%	47.6%	9.7%	10.3%	-0.5%
DSM	11.9%	5.2%	21.4%	8.5%	5.0%	3.6%
Pension Expense	81.4%	537.6%	115.1%	309.5%	24.9%	284.6%
Other O&M	6.4%	3.7%	14.6%	5.0%	3.5%	1.5%
Total Net Utility O&M Expense	8.9%	11.6%	12.0%	10.2%	2.9%	7.4%

- Pension expense increase is the key reason for the significant increase of total O&M in 2012 and 2013. The average annual growth for pension expense for 2012 and 2013 is 310% compared to 25% increase for the previous four years. In 2007, pension expense accounted for 0.5% of total utility O&M expenses. In 2013, pension expense accounts for 8.5% of total O&M expenses. The reasons for pension expenses are discussed separately in interrogatory responses related to Issue D4.

- The next significant difference is related to Customer care/CIS. The average annual growth for Customer care/CIS for 2012 and 2013 is 6.5% compared to 1.4% decrease for the previous four years. . Within the EB-2011-0226 Customer care/CIS proceeding, the Board approved a Settlement Agreement which established O&M related Customer Care service charges of $89.4 million for 2013.

- The next segment is related to DSM activities. The average annual growth for DSM for 2012 and 2013 is 8.5% compared to 5% increase for the previous four years. The plan follows the 2012-2014 DSM guidelines. The 2012 Settlement agreement was filed as part of Enbridge's multi-year DSM filing EB-2011-0295. 2013 DSM budget is driven by inflationary rate increase over the 2012 estimate.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

- Related to corporate costs the increases have been relatively constant. The average annual growth for RCAM for 2012 and 2013 is 9.7% compared to 10.3% increase for the previous four years. The RCAM amount is determined in accordance with the methodology approved by the Board in EB_2006-0034. The Company has retained MNP, to undertake an independent review and prepare an updated study of the RCAM costs for 2013. One of the purposes of the review is to ensure that the RCAM continues to satisfy all regulatory requirements, including the three-pronged test (cost incurrence, cost allocation and cost benefit). The reasons for corporate cost allocation increases are discussed separately in interrogatory responses related to Issue D5.

Other O&M

- The average annual growth for Other O&M for 2012 and 2013 is 5% compared to 3.5% increase for the previous four years. This demonstrates effective performance by the Company considering the cost pressures and increased business and compliance demands.

- There are two key reasons for the differences in Other O&M increases in the initial years and the later years of IR – a) Diminishing returns of productivity and b) Changes to business needs.

- In 2008, EGD signed for the first time, a five year incentive regulation agreement. Knowing that the utility would not be able to file a cost of service application for five years, the Company took a cautious approach so that it could fully understand the implications of the settlement to the business and all stakeholders (customers, employees and investors), and to ensure that we were fiscally responsible based on the challenging budget established as the base in our 2007 settlement. At the same time, the full impact of the economic recession was not fully understood. A key driver in the IR formula is “active customers” and economic conditions do have an impact on the number of active customers.

- The Company focused on productivity as expected during the incentive regulation term. The Company was able to defer costs in initial years and manage with the resources available without compromising on the safety of operating the distribution network. After the first two years, the Company realized that its spending levels were not sustainable, and that it could increase it’s spending and still be fiscally responsible.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

- In the last two to three years, there was increased focus on safety and reliability across the gas distribution industry and within EGD. The increased focus on safety and reliability is driven by aging infrastructure and compliance requirements. These needs require investing in resources and programs. The two expense areas that have seen increases in the last years, as a result of these business needs, are “employee related” and “outside services”.

- The increases in “Outside services” are due to the new Extended Alliance construction contract agreements, volume of work and expenses related to programs that are required for a safe and reliable system. These include:
  - Leak repair Sewer Laterals
  - Storage Maintenance Measurement & Regulation
  - Damage prevention locates Integrity Management related work and studies
  - Path to Zero including Environment, Health & Safety Technical training
  - Leak survey & corrosion work

Overall, the Company was prudent in its management of costs and strived to be productive and mitigate the cost pressures from sources beyond management’s control e.g. compliance requirements. This has resulted in keeping the other O&M increases to 3.5% in first four years and 5% in 2012 and 2013.

h) Inflation rates were provided in the Budget Letter for departments to develop the grass-roots budget (please refer to Ex A2/T2/S1/p9). When it is necessary departments apply the inflation rate to the cost items. Inflation is not applied to all costs but on a case-by-case basis where inflation is the cost driver, e.g. contract cost in Operations and IT hardware and software maintenance.
Refer to Interrogatory response I.O3.5.2 that addresses the cost pressures, inflation and productivity issues.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

BOARD STAFF INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p4/Table 2

Please file an additional table which provides historical actuals for 2011 and 2010, and an additional "2 year difference %" which reflects the increase for 2013 budget over 2011 actual.

RESPONSE

Please see the table provided on the following page.

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2013 Budget vs. 2011 Actual

Line No.	Particulars ($ millions)	Updated Budget 2013 (a)	Estimate 2012 (b)	Actual 2011 (c)	Actual 2010 (d)	2 Year Difference % (a-c)/c
1.	Salaries and Wages	$170.9	$160.7	$141.5	$133.8	20.8%
2.	Benefits	30.5	25.9	24.3	22.9	25.5%
3.	Short Term Incentive Program	20.3	19.4	25.2	19.7	-19.6%
4.	Employee Training and Development	4.1	4.0	5.6	2.9	-25.6%
5.	Materials and Supplies	5.5	5.5	5.2	5.1	5.9%
6.	Outside Services	79.0	77.9	63.2	60.8	25.0%
7.	Regulatory Proceeding Costs	7.3	5.8	4.8	5.8	52.2%
8.	Consulting	9.5	6.7	5.0	6.4	89.8%
9.	Repairs and Maintenance	2.0	1.9	1.4	1.7	41.4%
10.	Fleet	10.0	9.8	9.0	8.1	10.8%
11.	Rents and Leases	7.7	7.4	7.3	5.7	5.3%
12.	Telecommunications	3.7	3.6	3.1	3.5	17.0%
13.	Travel and Other Business Expenses	4.9	4.7	3.5	3.4	38.2%
14.	Memberships	3.4	3.2	4.0	3.6	-14.9%
15.	Claims, Damages and Legal Fees	0.8	0.8	1.6	1.7	-49.0%
16.	Interest on Security Deposits	2.7	1.9	1.0	0.5	162.2%
17.	Provision for Uncollectibles	15.2	13.7	21.5	11.5	-29.6%
18.	Internal Allocations and Recoveries	(25.3)	(25.1)	(25.7)	(24.8)	-1.9%
19.	Other	7.2	5.9	8.0	4.8	-9.5%
20.	Subtotal	359.3	333.8	309.5	277.1	16.1%
21.	Capitalization (A&G)	(37.7)	(31.4)	(24.5)	(24.3)	54.0%
22.	Capitalization	(69.2)	(65.3)	(55.3)	(52.6)	25.2%
23.	Non-Utility Allocations	(3.4)	(3.2)	(4.9)	(4.1)	-29.9%
24.	Subtotal Net Utility O&M Expense	249.0	233.9	224.9	196.1	10.7%
25.	Conservation Services	1.5	7.0	7.3	9.4	-79.3%
26.	Total Other Utility O&M Expense before Eliminations	250.5	240.9	232.2	205.5	7.9%
27.	Regulatory Eliminations					
28.	To eliminate Conservation Services and Overheads	(2.5)	(7.9)	(7.3)	-	-66.2%
29.	Incremental O&M Allocated to Unregulated Storage	(0.2)	-	(0.2)	-	0.0%
30.	Total Eliminations	(2.7)	(7.9)	(7.5)	-	-64.2%
31.	Total Other Utility O&M Expense	$247.8	$232.9	$224.7	$205.5	10.3%

Witnesses: K. Culbert
S. Kancharla
R. Lei
S. McGill

BOARD STAFF INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p5

Salaries and wages have increased by approximately 17.8% over 2011.

a) Please indicate what amount of this increase is attributable to:
   a. Merit increases
   b. New FTE additions

b) Please provide a table showing historical FTEs for each of 2007 to 2011, as well as forecast and budget FTEs for 2012 and 2013. Also provide the year over year increases in FTEs in this table. Provide the absolute and percentage FTE increase over the number of FTEs that are representative of the 2007 Board approved budget for salaries and wages. If this cannot be done exactly, please provide explanations and assumptions where necessary to accompany any estimates.

RESPONSE

a) The increase in salaries and wages is attributable to
   a. Merit increases: $10.1 million
   b. New FTE additions: $15.8 million

b) Please refer to the table below:

Witnesses: S. Kancharla
R. Lei
S. Trozzi

Enbridge Gas Distribution
Full Time Equivalents (FTE)

Line No.	Salary Bands	Actual 2007 *	Y/Y Change	Actual 2008 *	Y/Y Change	Actual 2009 *	Y/Y Change	Actual 2010 *	Y/Y Change	Actual 2011 *	Y/Y Change	Estimate 2012	Y/Y Change	Budget 2013
1.	Management	100	12	112	6	118	7	126	9	134	4	138	2	140
2.	Supervisory	1,112	(14)	1,098	(41)	1,058	30	1,087	93	1,181	212	1,393	59	1,452
3.	Union	728	(47)	681	(19)	662	(1)	661	(8)	653	47	700	(5)	695
4.	Subtotal	1,940	(48)	1,892	(53)	1,838	36	1,874	94	1,968	263	2,231	56	2,287
5.	Vacancies	130	(79)	51	(6)	46	27	72	44	116	(116)	-	-	-
6.	Total FTE	2,070	(127)	1,943	(59)	1,884	63	1,947	137	2,084	147	2,231	56	2,287

* Actuals do not include vacancies during the year. FTE's represent active employees only.

Line No.	Salary Bands	Board Approved 2007	Budget 2013	Incr/ Decr	% Incr/ Decr
1.	Management	250	140	(110)	
2.	Supervisory	955	1,452	497	
3.	Union	755	695	(60)	
4.	Total FTE	1,961	2,287	326	17%

BOARD STAFF INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref(1): Ex. D1/T3/S1/p5-para11 and p11-para32
Ref(2): EB-2011-0277 Decision, pp.14-17, issued May 10, 2012

1. Enbridge has requested increases to benefits of $4.5M at paragraph 5 of Ref(1), which includes increases attributable to "other post employment benefits". At para 32 of Ref(1) Enbridge states that, "The pension expense is a function of whether it is in a deficit position, a matter beyond the Company's control."

2. At page 9 of the Decision in Ref(2), the Board panel stated that:
While the Company may not bear responsibility for, and may have no ability to influence interest rates or the overall performance of the financial markets, it does have the ability, and did exercise its judgment in making investment decisions which did not yield results sufficient to fund the plan. That is not to say that the Board would require the Company to meet an unrealistic standard of success in its investment decisions, especially at a time when the markets were generally underperforming. But **when [Enbridge] adopted the noncontributory pension plan, it accepted the responsibility to maintain funding for it.** (emphasis added)

At p.10 of the Decision in Ref(2) the Board denied Enbridge's request for Z factor treatment for pension funding requirement.

a) What amount of the increases to benefits is attributable to "other post employment benefits"? Please indicate why the panel in this proceeding should approve this increase when Z factor treatment for pension funding was denied in EB-2011-0277.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
B. Yuzwa

RESPONSE

The portion of the increase to 2013 Benefits costs related to OPEBs is $2.9 million (of the total $4.5 million Benefits cost increase). This is not a pension cost.

In any event, the fact that Z-factor treatment was not permitted in 2012 for pension costs is not determinative in respect of 2013 pension costs.

The 2012 EB-2011-0277 pension service cost was within the purview of a Z-factor request related specifically to the parameters of Enbridge's Incentive Regulation ("IR") rate making model. The request was for an item which Enbridge proposed met all of the required Z-factor criteria and therefore should be allowed as an incremental amount to be recovered within Enbridge's IR rates. Pension costs of this nature are typically included in cost of service recoverable amounts and therefore by extension are included in ongoing rates within IR rates. Such amounts were not included in Enbridge's 2007 base year cost of service amounts immediately prior to its 2008-2013 IR term, due to the pension plan then being in a surplus and was in fact not permitted under the Income Tax Act to contribute at that time, which Enbridge believed contributed to the costs qualifying during IR as a Z-factor.

While the 2012 pension costs were not permitted as a Z-factor, they are a legitimate cost of service for 2013.

Pension costs are a legitimate cost of doing business which Enbridge has recovered in cost of service rates in various prior fiscal years as approved by the Ontario Energy Board when the plan was in a required annual funding position. In other prior fiscal years, when the plan was in a surplus, ratepayer rates would be reduced where no annual funding requirement existed. Pensions and related funding costs are one element of total compensation requirements which Enbridge must incur to compete for, attract and maintain employee resources. If pension costs were not incurred, an alternative form of compensation with similar long-term costs would be necessary to maintain Enbridge's overall competitive positioning. The details and competitive position of Enbridge, shown within the compensation report prepared by Mercer dated November 30, 2011, show that Enbridge's total compensation and required pension related costs are reasonable and by extension are legitimately recoverable costs.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
B. Yuzwa

As a final point, Enbridge does not accept the premise in this Interrogatory that changes in the pension plan led to an obligation for the Company to fund it.

There were two changes to the pension plan effective July 1, 2001 (July 1, 2002 for union members): 1) Reduction in plan benefits, and 2) Elimination of employee contributions. This impact of this was, and continues to be, favorable to the plan in the following ways:

1) Cost neutral: Enbridge's share of costs accruing each year was unchanged because the reduction in plan benefits was equal in value to the employee contributions which were eliminated.

2) Significant reduction in risk: With the reduced benefit formula, the plan is smaller than it otherwise would have been so market volatility has less impact on contribution requirements.

Investment decisions and the asset mix in particular are made in consideration of the following investment concepts:

- a higher exposure to bonds means lower expected returns and higher expected contributions, but there would be less contribution volatility; and
- a higher exposure to equities means higher expected returns and lower expected contributions, but there would be greater contribution volatility.

This risk/return tradeoff is a fundamental decision made by all pension plan sponsors and a significant majority of pension plans in Canada have asset mix similar to Enbridge (i.e. approximately 60% equities/40% bonds). Had Enbridge decided to go against standard convention and invest all or most of its assets in bonds to reduce contribution volatility, the surplus that previously existed would have quickly eroded and contributions would have been required years sooner.

In summary, the ongoing costs of the pension plan are consistent with that when the plan was contributory, but the required contributions are far less volatile since the plan size is smaller than it otherwise would have been. And while an asset mix more heavily weighted to bonds would not have suffered the same losses in recent years, the long-term expected contributions would be higher.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p5/para12 and page8-9/para 23

a) Please provide a breakdown of this $1.1 million increase by the factors described at the above reference.

b) Please explain why an increase in customer base has a direct effect on the costs described?

c) While the increase in outside services is only $1.1M over 2012, there is a significant increase 2012 over 2011.

d) Why has Enbridge decided to make significant increases to its advertising program in 2012? What is the overall increase vs. the overall advertising budget?

e) Why has Enbridge decided to increase activities on the sewer lateral programs? Is there a reason that increased spending on these activities was not contemplated in previous years to smooth costs?

f) To what extent do “inflationary pressures” weigh on the budgetary increases? Why is it a separate category?

RESPONSE

a) Please refer to Exhibit D1, Tab 3, Schedule 1, page 16, lines 23 to 32.

b) There are incremental costs directly related to the attachment of new customers. These costs are operating and capital in nature. As a result, the total costs will increase as a result of an increase in customer base.

c) The increase 2012 over 2011 is primarily attributed to the public safety communication program and increased activities in the sewer lateral program. The

Witnesses: S. Kancharla
R. Lei
C. Meyer
L. Lawler
J. Briggs

sewer lateral program costs were the subject of significant review in the Company's most recent rate applications, principally in EB-2011-0277 for the establishment of 2012 rates.

d) As descripted in Exhibit D1, Tab 21, Schedule 1, Enbridge plans additional communication including community outreach initiatives that relate to core messages around safety, including targeted audiences such as seniors and schools.

Safety is a priority for the company and its employees and by extension raising customer awareness about safety is of critical importance. Plans include continued communication outreach through media including radio and potentially new outlets such as transit and cinema, as well as increased use of social and electronic media including video and our website. Agency support will be used to assist with the development of new safety initiatives including the new or updated safety program material for key groups including first responders, seniors and schools and outreach to community media in the Company's more than 100 franchise communities.

This is being done to improve customer satisfaction with Enbridge's safety communications given that research indicates that only 42% of the Company's customers rate the quality of safety communications as excellent or very good. The themes of these important public safety messages will be related to topics including carbon monoxide testing, call before you dig reminders, smell of gas, sewer safety and, particularly in rural areas, appropriate customer responses to natural gas meter and regulator safety following large snowfalls.

Finally, the increase in spending is also a reflection of the fact that there are areas within Enbridge's franchise territories that do not see the same level of communication and media safety initiatives as occurs within the urban centres.

e) Enbridge has increased activities on sewer laterals due to its evolving understanding of the nature of the sewer lateral risk over the course of the IR period. Growing awareness from the public and contractors and plumbers has also increased the required activities. The spending on these activities has increased as a result, and will continue for the foreseeable future as awareness grows regarding the need to call for a Sewer Safety Inspection when clearing a blocked sewer outside the foundation walls of a premise.

f) Please refer to the response to i) on Board Staff interrogatory, Exhibit I, Issue D1, Schedule 1.3.

Witnesses: S. Kancharla
R. Lei
C. Meyer
L. Lawler
J. Briggs

BOARD STAFF INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p6/para16

a) Please explain this additional $2.9M for the "path to Zero" initiative, and why this project is necessary and incremental to Enbridge's core safety initiatives.

b) Is the project purely for the purpose of reducing safety incidents for the *regulated* company?

c) Please provide a breakdown of the "incremental services required" by cost type.

RESPONSE

a) The Company's Path to Zero initiative has four focus areas – System Governance (Charter & staff Central Safety and Local Safety Committees), Safety Leadership Competencies (Safety management training and skills development through employee hazard awareness and safety engagement), Process Improvement Employee Safety (develop/update safety policies and procedures plus develop and update data collection system), and Implementation Support (Develop rollout plan and training requirements plus collect and analysis data). The goal of the Path to Zero initiative is twofold: zero worker safety events (medical aids, lost time injuries, critical injuries, fatalities); and zero public safety events (zero damages due to first, second, or third parties), and zero leaks (due to assets coming to the end of their useful life). This goal is aspirational, but is useful to assist staff to think differently about their safety, their colleagues' safety, and public safety, to attempt to drive out of the box thinking and a step change in safety performance.

An assessment of Enbridge's safety management systems conducted in 2010 identified cultural and systemic gaps that are hindering Enbridge's attainment of the Path to Zero initiative. Improvement areas to achieve the goal include:

Witnesses: J. Briggs
C. Hanlon
S. Kancharla
R. Lei

- Establishing an integrated organization to manage key safety related processes
- Establishing a comprehensive risk management system
- Improving contractor safety
- Improving environment, health and safety programs

Building a strong safety culture, organization, metrics and auditing are key to sustaining process safety and operational excellence. Operational effectiveness is a function of standards and the level of execution of those standards. Strong leadership through visible and demonstrated commitment, clear and meaningful policies and principles, challenging goals and plans and high standards of performance is required to ensure a strong safety culture which will support operational excellence.

b) The Path to Zero initiative is directed solely at the regulated utility, however, the purpose is more than simply reducing safety incidents. As explained in part a) above, a strong safety culture supports and ensures the success of risk based operations which lead to operational excellence, improved operational discipline and prevention of incidents. Areas of improvement include:

- Emergency preparedness and contingency planning
- Risk assessment and process hazards analysis
- Process safety information
- Mechanical integrity
- Management of change of facilities

c) The $2.9 million is comprised of the following cost types:

- Consulting contract - $2.45 Million – To assist in the development of an Integrated Organizational Structure for safety and Safety Process Teams designed to improve the flow of information and provide a streamlined decision-making process along lines of accountability or ownership. Structural elements include governance committees to address decision-making at various levels of the Company, as well as Process Improvement Teams or networks focused on continuing improvement in key safety processes.
- Internal Labour/travel/other materials & supplies - $0.45 Million

Witnesses: J. Briggs
C. Hanlon
S. Kancharla
R. Lei

BOARD STAFF INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p5/para17

Why is Enbridge budgeting an additional $1.5 million for uncollectible accounts when natural gas rates are at or near historical lows? Did Enbridge consult any other energy price forecast other than the Consensus forecast? Is this budget changed when the gas prices change?

RESPONSE

Billed receivables for 2013 are expected to be higher due to increased gas cost and customer additions. Based upon the Consensus forecast current at the time, gas prices were at historic lows and consequently were predicted to rise 8 to 11% in 2013 from these historic low levels. The effective bad debt rate in 2013 was also increased due to higher bad debt experienced in recent years; and higher customer bills, due to higher gas cost, which are more difficult to pay.

The Company did not consult any other forecast given that the Consensus Forecast is a compilation of quarterly energy price forecasts from industry consultants. The Company believes that this approach provides a balanced price expectation for the industry. Use of the Consensus Forecast is standard Company practise.

At the time the budget is set the Company considers the forecast cost of gas in the determination of the budget amount for uncollectible accounts.

Witnesses: S. Kancharla
R. Lei
S. McGill

BOARD STAFF INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p9/para27

Enbridge reports a $1.2 million increase in Rents and Leases at the reference above.

a) Please indicate what amount is for land easements, and what amount is for business growth at the head office facility.

b) Is the growth at the head office facility associated entirely with regulated utility functions?

RESPONSE

a) The table below provides a breakdown of rents and leases as requests:

$ Million	Estimate 2012	Historic 2011	Difference
Building Rents and Leases	3.4	2.7	0.7
Land Easement	4.0	3.6	0.4
Total	7.4	6.3	1.1

b) The $0.7 million increase in building rents and leases in 2012 is due to planned acquisition of additional office space to accommodate employee growth at the head office facility entirely for regulated utility functions.

Witnesses: S. Kancharla
R. Lei

BOARD STAFF INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p10/para31

Enbridge states that, "The regulatory presentation of 2007 Board Approved amounts by department in some exhibits is an arbitrary allocation that simply involved prorating the total reduction… **An attempt to compare the costs line by line between the two distinct time period would lead to inaccurate interpretations** as the roles and responsibility of groups within departments have changed." (emphasis added)

1) How does Enbridge propose that a useful comparison be made between 2007 Board approved amounts and the 2013 application?

2) Would 2007 historical actual be a more appropriate comparator? If not, describe a suitable alternate form of comparison.

RESPONSE

1) The O&M costs by five categories at Exhibit D1, Tab 3, Schedule 1, page 2, Table 1 are a useful comparison between 2007 Board Approved amounts and the 2013 application because they are not materially affected by the proration and reorganizations. The allocation of the Board Approved 2007 budget into departmental budget amounts was undertaken for internal control purposes between those amounts and 2007 actual.

2) 2007 historical actual by cost type at the overall company level would be a more appropriate comparator as opposed to by department as the overall cost type is relatively stable year over year. Please refer to the response to Board Staff Interrogatory #1 at Exhibit I, Issue D1, Tab 1, Schedule 1.1.

Witnesses: S. Kancharla
R. Lei

BOARD STAFF INTERROGATORY #12

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p11/para32

Is Enbridge requesting any approval of the Board in this proceeding for the following:

- CC/CIS
- DSM
- RCAM

RESPONSE

Enbridge's application is requesting Board Approval for the recovery in rates of amounts for each of CC/CIS and DSM which were already approved by the Board in previous proceedings. Further, the application is requesting approval of an amount in rates for RCAM in conjunction with the adoption of the RCAM review performed by Myers Norris Penny, a third party consultant.

Please refer to the information provided within the Impact Statement M1, Tab 1, Schedule1, filed June 1, 2012.

Witnesses: K. Culbert
R. Lei
B. Yuzwa

BOARD STAFF INTERROGATORY #13

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p12/para33

a) Are the same 'salaries and wages' escalations applied to FTEs that are capitalized and recorded under the capital budget for 2013 and 2012? Please comment on the upward effect on the 2013 capital budget and 2012 forecast?

b) If the Board's Decision orders a reduction to Salaries and Wages, does Enbridge intend to apply the same hypothetical reduction to FTEs that are capitalized? If not, why not.

RESPONSE

a) Yes. The same "salaries and wages" escalation are applied to FTEs that are capitalized and recorded under the capital budget for 2013 and 2012. As a result, 2013 capital budget and 2012 forecast are impacted by the upward effect.

b) Yes.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

BOARD STAFF INTERROGATORY #14

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p12/para34

Table 5 provides year to year FTE complements. It would appear that there has been departmental reorganization sometime between 2007 and 2011 which has affected the number of FTEs in Supervisory and Management roles. There appears to be no change to classification of union (i.e. bargaining) employees.

a) Was there a reorganization as described above?

b) What was the purpose of this reorganization and reclassification of employees?

c) Is there any difference in any form of compensation between the two classes of employees (supervisory vs. management)

d) Please recast Table 5 to show FTE numbers in Budget 2013, Estimate 2012, and Historical 2011 staff in Supervisory and Management roles on the basis of which group they would have been recorded in 2007 Board approved.

e) Please provide a table showing the number of supervisory & management FTEs combined at Enbridge for each year since 2007. Provide actual numbers where possible, and forecast for 2012, and budget for 2013.

   i. Please explain why there is a 32% increase in supervisory and management roles since 2007, and an 8% *reduction* in union staff over the same period. Please account for any explanatory trends associated with employee complement and type, and the type of work that each class of employee performs. Has the nature of work at Enbridge changed significantly in 2013 versus 2007?
   ii. Please explain why there is approximately a 9.7% increase in supervisory & management' FTEs for 2012 forecast over 2011 actual.
   iii. Please explain why there is a further increase of approximately 4% in 'supervisory & management' FTEs for 2013 budget over 2012 forecast.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

iv. Please compare the absolute increase in FTEs for 2013 budget over 2007 historical versus the growth in the number of customers at Enbridge.

RESPONSE

a) Enbridge did not undertake a re organization. However, the Company now groups the management and supervisory employees differently from the 2007 Board reporting. This current employee classification is a more reflective representation of how we administer programs at Enbridge based on employee roles.

b) See response in a.

c) All class of permanent employees are eligible for Short Term Incentive Compensation (STIP), however only Management employees are eligible for Long Term Incentive Compensation Programs, which include Restricted Stock Units.

d) Enbridge is unable to provide the requested information, except by examining records for individual positions, which would be unduly time-consuming.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

e)

Enbridge Gas Distribution
Full Time Equivalents (FTE)

Line No	Salary Bands	Board Approved 2007	2007	2008	2009	2010	2011	2012	2013
1.	Supervisory & Management	1,206	1,212	1,211	1,176	1,213	1,315	1,531	1,592
2.	Union	755	728	681	662	661	653	700	695
3.	Total FTE	1,961	1,940	1,892	1,838	1,874	1,968	2,231	2,287
4.	Vacancies		130	51	46	72	116	-	-
5.	Total FTE	1,961	2,070	1,943	1,884	1,947	2,084	2,231	2,287

*Vacancies are not included in the actual FTE's but are included in the budget and estimate

i. The increase in supervisory and management roles is attributed to the heightened focus on safety and pipeline integrity. This has resulted in additional supervisory and management positions in such areas as, pipeline evaluation and inspection, damage prevention, environmental health and safety, safety and technical training, GTA reinforcement project and safety supervisors. These positions are not unionized due to the requirements of the role, such as the need for a professional designation or a people leader or a quality control function. In reference to the Company's declining unionized environment, through attrition Enbridge has reduced some field positions for work that is no longer required.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

ii. The increase in supervisory and management FTE's for 2012 forecast over 2011 actual is also due to the increased focus on safety and pipeline integrity as explained.

iii. The increase of 4% in supervisory & management for 2013 is also attributed to increases in safety and pipeline integrity.

iv. The table below indicates the FTE growth in comparison to the customer growth.

	Budget 2013	Actual 2007	2013 vs. 2007	% Increase (Decrease)
FTEs	2,287	2,070	217	10.5%
Unlock Customers	2,020,962	1,824,789	196,173	10.8%

Witnesses: S. Kancharla
R. Lei
S. Trozzi

BOARD STAFF INTERROGATORY #15

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p12/para33 and 34

a) Please complete the following table based on the information provided in paragraphs 33 and 34 at the above reference :

	FTEs total 2013	New FTEs 2013	FTEs total 2012	New FTEs 2012	FTEs 2011 (historical)
Integrity Management					
… (add columns as necessary)					

b) To the extent that Enbridge can provide a more meaningful table that provides the FTE increases by department or function, please provide an additional table, which similarly shows incremental and department/function number of FTEs before the incremental additions.

RESPONSE

a) - b) The Company's FTE data is structured by department but it is more meaningful to interpret new FTEs in terms of function so positions with a similar nature that reside in various departments are manually summarized by function. Please refer to the following table for the FTE breakdown by department and function.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

Department	FTEs Total 2013	New FTEs 2013	FTEs Total 2012	New FTEs 2012	FTEs Total 2011
Finance	76	1	75	6	69
Customer Support	93	0	93	8	85
Energy Supply, Storage, Regulatory	65	(1)	66	14	52
Legal & Corporate Services	18	1	17	3	14
Operations	1,207	28	1,179	41	1,138
Information Services	180	6	174	7	167
Business Development & Customer Strategy	160	(1)	161	6	156
Human Resources	72	(1)	73	5	68
Pipeline Integrity & Safety	366	21	345	68	277
Public & Government Affairs	33	2	31	3	28
Corporate	16	0	16	0	16
Total	2,287	56	2,231	161	2,070

Function breakdown of New FTEs		New FTEs 2013		New FTEs 2012	
Distribution asset management				20	
Integrity management		20		5	
Worker and public safety		8		12	
System operations		7		7	
Measurement and regulation inspectors		5		10	
Leak management		5		13	
Damage prevention		2		5	
Incident response		2		3	
Union collective agreement				5	
Succession planning for retirements				5	
Pipeline evaluation and inspection				16	
Safety and technical training				10	
IT support		6		7	
Customer support				8	
HR support				5	
Regulatory support and gas control management				5	
GTA reinforcement project				9	
DSM and conservation services				5	
Legal contract leads and records management				3	
Senior advisor, government relation				1	
Other (effectivity, maternity leaves etc.)		1		7	
Total		56		161	

Witnesses: S. Kancharla
R. Lei
S. Trozzi

BOARD STAFF INTERROGATORY #16

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D1/T3/S1/p13-14

a) Why has Enbridge decided to compare O&M cost per customer for 2013 against 2004?

b) Please provide a graph of Table 6, row 1 for the period 2007 to 2013.

c) Please provide a table of O&M cost increase (in constant dollars using GDP-IPI FDD) for 2013 budget against:
   a. 2007 historical actual
   b. 2008 historical actual
   c. 2009 historical actual
   d. 2010 historical actual
   e. 2011 historical actual
   f. 2012 historical actual

Compare these increases against the incremental customer additions over each period, and provide the reasoning for the increases.

d) Please provide O&M cost increase (in constant dollars using GDP-IPI FDD) for 2012 budget against 2011 historical actual. What is the source of this significant increase vs. all other years in Table 6?

RESPONSE

a) Consistent with the rate case filing in 2007, Enbridge provided the ten-year data from 2004 to 2013 and compared 2013 Test Year to the starting point in 2004.

b) Meaningful cost comparisons with 2007 can only be made if comparisons are made on a consistent basis. Therefore, incremental costs over and above categories of costs incurred in 2007 should be removed to properly determine the performance from 2007 to 2013. As a result, two major incremental cost drivers are identified

Witnesses: S. Kancharla
R. Lei

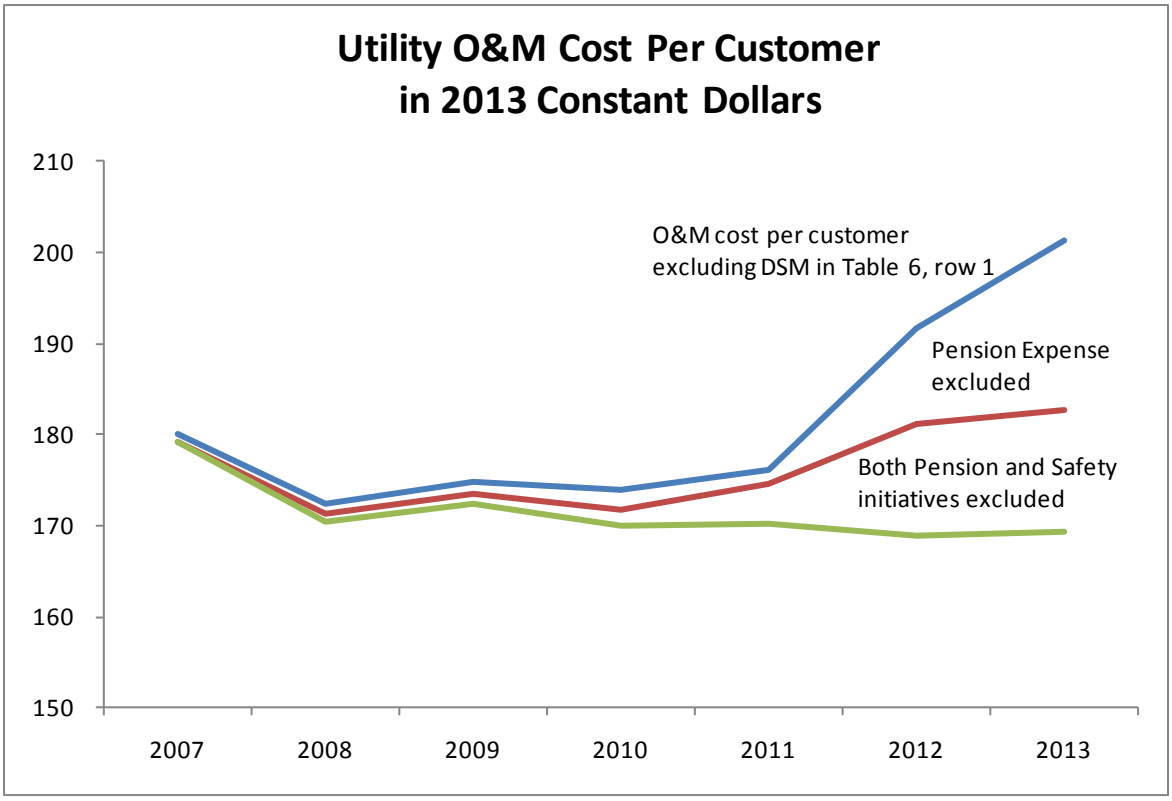
which cause an increase in the O&M cost per customer, particularily in 2012 and 2013: pension expense and incremental safety initiatives. Pension expense increases significantly in 2012 and 2013, which is a fixed cost primarily driven by external factors the Company has limited ability to influence. Also, incremental safety initiatives result in additional costs in 2012 and 2013 which have arisen from the Company's increased focus on safety and compliance with the new safety regulations. The following table and graph exhibit that the O&M costs excluding pension expense and incremental safety initiatives have decreased by 5.5% from 2007 to 2013. It is evident that the O&M cost at the same base as 2007 has decreased over the time period of 2007-2013 mostly as a result of productivity gains achieved by the Company.

Table 1
Utility O&M Cost Per Customer
in 2013 Constant Dollars

Line No.		Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Estimate 2012	Budget 2013	2013 vs. 2007
1.	Utility O&M cost per customer*	$180.03	$172.30	$174.91	$173.86	$176.18	$191.73	$201.23	11.8%
2.	Pension expense excluded	179.13	171.29	173.47	171.70	174.48	181.20	182.78	2.0%
3.	Pension expense and safety initiative excluded	179.13	170.33	172.50	169.95	170.14	168.92	169.33	-5.5%

* DSM costs are excluded

Witnesses: S. Kancharla
R. Lei



c) The increase in 2013 Budget primarily results from an increase in pension expense and safety and integrity spending based on the tables of O&M cost increase below:

Witnesses: S. Kancharla
R. Lei

Table 2

		Col. 1 O&M cost per Customer in Table 6, row 1	Col. 2 Pension expense excluded	Col. 3 Incremental customer additions	Col. 4 Col. 1 vs. Col. 2	Col. 5 Col. 1 vs. Col. 3	Col. 6 Col. 2 vs. Col. 3
	2013 Budget against:						
a.	2007 historical actual	11.8%	2.0%	10.8%	9.7%	1.0%	-8.7%
b.	2008 historical actual	16.8%	6.7%	8.4%	10.1%	8.4%	-1.7%
c.	2009 historical actual	15.0%	5.4%	7.1%	9.7%	8.0%	-1.7%
d.	2010 historical actual	15.7%	6.4%	4.9%	9.3%	10.8%	1.5%
e.	2011 historical actual	14.2%	4.8%	3.1%	9.5%	11.1%	1.7%
f.	2012 estimate	5.0%	0.9%	1.8%	4.1%	3.1%	-1.0%

Table 3

		Col. 1 O&M cost per Customer in Table 6, row 1	Col. 2 Pension expense and Safety excluded	Col. 3 Incremental customer additions	Col. 4 Col. 1 vs. Col. 2	Col. 5 Col. 1 vs. Col. 3	Col. 6 Col. 2 vs. Col. 3
	2013 Budget against:						
a.	2007 historical actual	11.8%	-5.5%	10.8%	17.2%	1.0%	-16.2%
b.	2008 historical actual	16.8%	-0.6%	8.4%	17.4%	8.4%	-8.9%
c.	2009 historical actual	15.0%	-1.8%	7.1%	16.9%	8.0%	-8.9%
d.	2010 historical actual	15.7%	-0.4%	4.9%	16.1%	10.8%	-5.3%
e.	2011 historical actual	14.2%	-0.5%	3.1%	14.7%	11.1%	-3.6%
f.	2012 estimate	5.0%	0.2%	1.8%	4.7%	3.1%	-1.6%

d) The increase in 2012 Estimate over 2011 Actual primarily results from an increase in pension expense and safety and integrity spending based on the table of O&M cost increase below:

Witnesses: S. Kancharla
R. Lei

Table 4

		Col. 1 O&M cost per Customer in Table 6, row 1	Col. 2 Pension expense excluded	Col. 3 Incremental customer additions	Col. 4 Col. 1 vs. Col. 2	Col. 5 Col. 1 vs. Col. 3	Col. 6 Col. 2 vs. Col. 3
	2012 Estimate against:						
a.	2011 historical actual	8.8%	3.8%	1.2%	5.0%	7.6%	2.6%

Table 5

		Col. 1 O&M cost per Customer in Table 6, row 1	Col. 2 Pension expense and Safety excluded	Col. 3 Incremental customer additions	Col. 4 Col. 1 vs. Col. 2	Col. 5 Col. 1 vs. Col. 3	Col. 6 Col. 2 vs. Col. 3
	2012 Estimate against:						
a.	2011 historical actual	8.8%	-0.7%	1.2%	9.5%	7.6%	-2.0%

Witnesses: S. Kancharla
R. Lei

BOARD STAFF INTERROGATORY #17

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Ex. D5 /Tab 2/ Sch 5 / Table 1

The table provided shows the summary of O&M Expenses by category from 2007 to 2013. Please add two rows: One that shows the year over year percentage increase in total costs and another that shows the annual rate of inflation in the Canadian economy year over year.

RESPONSE

Table 1
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
From 2007 Board Approved to 2013 Budget

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.	Categories ($ Millions)	Updated Budget 2013	Estimate 2012	Actual 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007	Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$79.2	$87.5	$87.5	$82.5	$84.4	$90.8
2.	Regulatory Cost Allocation Methodology(RCAM)	32.1	30.2	26.7	24.3	21.2	19.1	18.1	18.1
3.	Demand Side Management (DSM)	31.4	28.1	26.7	25.5	24.3	23.1	22.0	22.0
4.	Pension Expense	37.3	20.6	3.2	4.0	2.6	1.7	1.5	1.7
5.	Other O&M	247.8	232.9	224.7	205.5	201.5	197.0	196.0	193.6
6.	Total Net Utility O&M Expense	$438.1	$402.2	$360.5	$346.7	$337.0	$323.4	$322.0	$326.2
7.	Year over Year Percentage Increase in Total Costs	8.93%	11.56%	3.97%	2.90%	4.19%	0.45%		
8.	Annual rate of inflation in GDP-IPI-FDD	1.73%	1.72%	0.72%	2.73%	1.54%	2.04%		

Witnesses: S. Kancharla
R. Lei

BOMA INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 1, Page 5 of 29.

With respect the merit increase guidance: 3.3% salary increase for non-union employees and 3.5% salary increase for union employees please provide any studies indicating how this increase compares with merit only increases in other industries. Please confirm that this increase is in addition to inflation adjustments and illustrate the total compensation increases.

RESPONSE

See attached Conference Board of Canada, Compensation Planning Outlook, Report October 2011.

The salary increase of 3.3% for non-union employees is an annual merit increase. There are no additional inflation adjustments. The union increase is 3% effective January 1, 2013 and 1% effective July 1, 2013. The union increase is a negotiated annual increase. There are no inflation adjustments for union staff in addition to the negotiated annual increase.

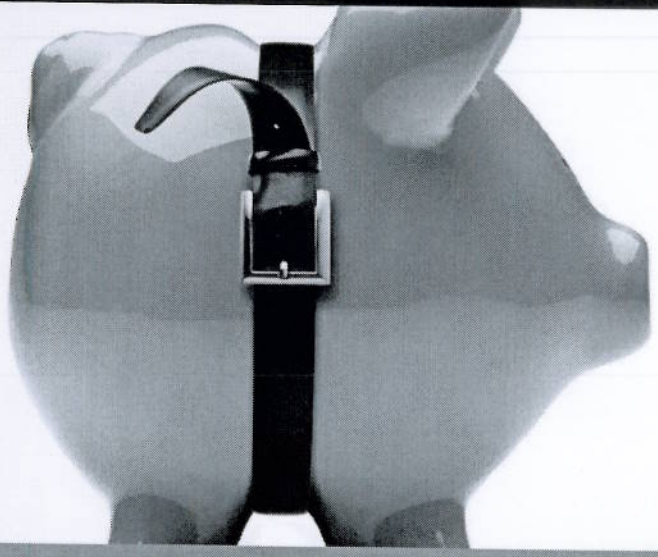
The Conference Board Compensation report indicates that the average increase for all employees in the oil and gas industry is 4.3%. Other industries range from salary increases of 2.8% to 4.1%.

The Compensation report indicates that the average increase for unionized positions among all employees is 3.1% for clerical, and 3.2% for trades.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

The Conference Board of Canada
Insights You Can Count On

Report October 2011



Compensation Planning Outlook 2012

HUMAN RESOURCE MANAGEMENT

Table 2
2012 Planned Compensation Increases, by Employee Group
(non-unionized employees)

	Policy line (range increase; %)		Total increase to budget (%)		Average increase among all employees (%)	
Employee group*	**zeros included**	**zeros excluded**	**zeros included**	**zeros excluded**	**zeros included**	**zeros excluded**
Senior executives	1.9	2.3	3.2	3.4	3.1	3.2
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Executives	1.9	2.3	3.3	3.4	3.1	3.2
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Management	1.9	2.3	3.3	3.4	3.1	3.2
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Professional—technical	1.9	2.2	3.3	3.4	3.1	3.2
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Professional—non-technical	2.0	2.3	3.3	3.4	3.1	3.2
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Technical and skilled trades	2.0	2.3	3.2	3.3	3.1	3.2
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Clerical and support	1.9	2.2	3.3	3.3	3.1	3.1
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Service and production	2.1	2.4	3.2	3.3	3.0	3.1
	2.0	*2.0*	*3.0*	*3.0*	*3.0*	*3.0*
Overall	**1.9**	**2.2**	**3.2**	**3.3**	**3.1**	**3.1**
	2.0	***2.0***	***3.0***	***3.0***	***3.0***	***3.0***

*See Table 1 for definitions.
Note: For each result, the top number is the average (mean) and the bottom number (in italics) is the median.
Source: The Conference Board of Canada.

Table 4
2012 Planned Compensation Increases by Industry, Sector, and Region
(non-unionized employees)

	Policy line (range increase; %)		Total increase to budget (%)		Average increase among all employees (%)	
	zeros included	zeros excluded	zeros included	zeros excluded	zeros included	zeros excluded
Overall (n=371)	**1.9**	**2.2**	**3.2**	**3.3**	**3.1**	**3.1**
Industry						
Oil and gas (n=24)	2.4	2.8	4.5	4.5	4.3	4.3
Natural resources, excluding oil and gas (n=15)	2.4	2.4	4.2	4.2	4.1	4.1
Chemical, pharmaceutical, and allied products (n=13)	2.1	2.3	3.8	3.8	3.5	3.5
Construction (n=6)	2.4	2.4	3.4	3.4	3.4	3.4
Services—professional, scientific, technical (n=20)	2.0	2.3	3.7	3.7	3.4	3.4
High technology (n=24)	2.1	2.6	3.0	3.2	3.2	3.2
Education and health (n=17)	2.0	2.5	3.4	3.4	3.0	3.0
Not-for-profit (n=21)	1.6	2.0	3.2	3.2	3.0	3.0
Services—accommodation, food, personal (n=19)	1.8	2.4	3.0	3.0	3.0	3.0
Finance, insurance, and real estate (n=68)	1.7	2.1	3.1	3.1	2.9	2.9
Food, beverage, and tobacco (n=10)	2.0	2.0	3.3	3.3	2.9	2.9
Wholesale trade (n=9)	2.3	2.3	3.2	3.2	2.9	2.9
Transportation and utilities (n=35)	1.9	2.1	3.0	3.3	2.8	3.0
Government (n=35)	2.1	2.4	2.9	3.3	2.7	2.9
Manufacturing (n=27)	1.6	1.9	2.7	2.7	2.6	2.6
Communications and telecommunications (n=13)	1.8	2.0	2.6	2.6	2.6	2.6
Retail trade (n=15)	1.5	1.8	2.9	2.9	2.4	2.4
Sector						
Private sector (n=279)	1.9	2.2	3.3	3.3	3.2	3.2
Public sector (n=92)	1.9	2.3	2.9	3.1	2.6	2.8
Region						
Atlantic provinces (n=9)	2.3	2.3	2.7	2.7	2.7	2.7
Quebec (n=40)	2.2	2.2	3.1	3.1	3.0	3.0
Ontario (n=179)	1.6	2.1	2.9	3.1	2.7	2.8
Manitoba (n=11)	2.0	2.0	3.0	3.0	3.3	3.3
Saskatchewan (n=20)	2.2	2.2	4.2	4.2	3.9	3.9
Alberta (n=78)	2.4	2.5	3.8	3.8	3.6	3.6
British Columbia (n=31)	1.7	2.2	3.3	3.3	3.2	3.2

Note: Sample sizes indicate the number of organizations providing a response for at least one actual or projected increase.
Source: The Conference Board of Canada.

Table 18
Base Pay Increases*
(per cent, except for years in contract)

		Average no. of years in contract (n=87)	Year 1 2011 (n=86)	Year 2 2012 (n=84)	Year 3 2013 (n=64)
Contracts negotiated since Jan. 1, 2011	(mean)	3.3	2.0	2.0	2.3
	(median)	*3.0*	*2.0*	*2.0*	*2.3*

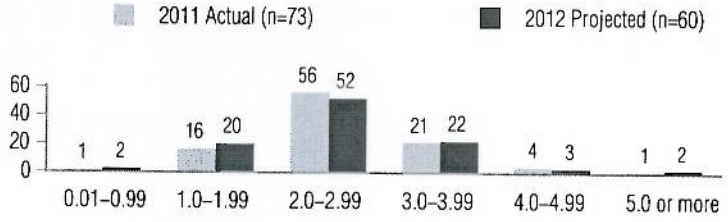
		Average no. of years in contract (n=76)	Year 1 2012 (n=70)	Year 2 2013 (n=69)	Year 3 2014 (n=53)
Contracts to be negotiated before Dec. 31, 2012	(mean)	3.1	2.0	2.2	2.5
	(median)	*3.0*	*2.0*	*2.3*	*2.3*

*A base pay increase is the rate for the year specified (includes any cost of living allowance increases).
Source: The Conference Board of Canada.

NEGOTIATION ISSUES

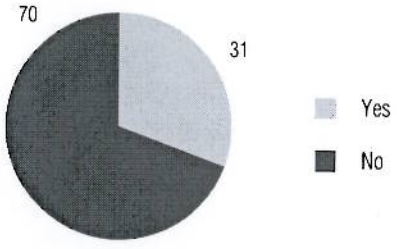
Despite some early tensions in negotiations in 2011, the majority of organizations view the overall labour–management climate as cooperative (56 per cent). Only 5 per cent found it uncooperative. Almost three-quarters of organizations (71 per cent) anticipate that their relationship with unions will remain the same in 2012. The remainder was equally split between those who feel it will become less cooperative and those who feel it will become more cooperative. When asked about their expectations of a work stoppage in 2012, no organizations reported that a stoppage "definitely will occur." However, 3 per cent indicated that there was a strong possibility of a work stoppage, and 15 per cent reported one may or may not occur. The remaining 82 per cent are fairly confident there will be no work stoppages.

Chart 18
Distribution of Base Pay Increases*
(percentage of organizations)



*A base pay increase refers to the average increase applied to the base wage rate for the year specified (includes any cost of living allowance increases).
Source: The Conference Board of Canada.

Chart 19
Prevalence of Short-Term Incentive Pay for Unionized Employees
(n=203; percentage of unionized organizations)



Note: Totals do not add to 100 per cent due to rounding.
Source: The Conference Board of Canada.

BOMA INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 1, Page 13 of 29

"The O&M cost per customer for 2013, in constant dollars, has slightly increased by 0.2% since 2004 due to FTE growth, increased customer numbers, and higher safety requirements, partially offset by the continued productivity improvements. Please explain how and why an increase in the number of customers would increase O&M cost per customer?

RESPONSE

An increase in the number of customers requires the Company to invest in capital assets and other resource to create incremental capacity, which translates into higher operating and maintenance costs. However, the incremental costs are largely offset by the continued productivity improvements.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

BOMA INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 2, Page 9 of 10

Please explain why the amount for severances has doubled from the 2012 Estimate to the 2013 Budget.

RESPONSE

The Company is placing a greater emphasis on performance management ensuring employees are achieving the required results. Employees are expected to achieve their performance objectives, which assists the company in achieving financial and operational results. As the performance management process continues to be refined, EGD expect severances to increase over the next 2 or 3 years, and then stabilize afterwards.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

BOMA INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 2, Page 10 of 10.

With respect to the statement: "The relocations were a result of succession planning with a focus on leadership", please explain how relocation costs between Enbridge Gas Distribution and other Enbridge units are handled. Are relocations of Enbridge Gas Distribution Staff designed to benefit Enbridge as a whole charged to Enbridge Gas Distribution? Are relocations from other Enbridge Units to Enbridge Gas Distribution also charged to Enbridge Gas Distribution?

RESPONSE

Employees may be relocating from various other Enbridge units, but relocation costs are only incurred for those employees moving to Enbridge Gas Distribution or within Enbridge Gas Distribution. The relocation program is designed to ensure that employees are not "out of pocket" for any expenses involved in their move.

No other Enbridge business unit employee relocation costs are charged to Enbridge Gas Distribution.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

BOMA INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 2, Page 10 of 10.

With respect to the statement: "The relocations were a result of succession planning with a focus on leadership development to ensure the future success of the Company", please indicate whether the company is Enbridge Gas Distribution or Enbridge Inc.?

RESPONSE

The reference made regarding relocations and the future success of the Company is specifically intended for Enbridge Gas Distribution ("EGD"). EGD only covers the cost of relocations when an employee is moving to EGD or within EGD.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

CME INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1, Tab 1, Schedule 1, page 1 of 2

EGD provides its Operating Cost Summary in Table 1. Please broaden Table 1 so that the Operating Cost Summary includes actual information for the years 2007, 2008, 2009, 2010 and 2011.

RESPONSE

Table 1 has been updated to show the actual information for the years 2007, 2008, 2009, 2010 and 2011.

Table 1
Operating Cost Summary

Line No.	($millions)	2007 Board Approved	2007 Actual Normalized	2008 Actual Normalized	2009 Actual Normalized	2010 Actual Normalized	2011 Actual Normalized	2012 Bridge Year	2013 Test Year Ex M1,T1,S4
1.	Gas costs	2,174.6	2,047.7	2,137.8	1,862.6	1,450.7	1,383.7	1,515.5	1,307.9
2.	Operation and maintenance	326.2	322.0	323.4	336.9	346.2	360.5	402.2	438.1
3.	Depreciation and amortization expense	227.3	225.7	236.7	251.0	266.9	276.6	291.6	300.8
4.	Fixed financing cost & debt red. prem.	1.3	0.5	1.0	6.8	5.1	3.1	2.5	2.3
5.	Interest equivalent to DRDA	-	2.7	-	-				
6.	Notional utility account recovery	9.2	9.2	-	-			-	-
7.	EGD share of IR tax savings	-		7.4	9.6	16.0	22.3	25.6	-
8.	Municipal and other taxes	45.9	43.6	44.8	44.4	40.7	37.6	38.8	40.1
9.	Operating costs	2,784.5	2,651.4	2,751.1	2,511.3	2,125.6	2,083.8	2,276.2	2,089.2
10.	Income tax expense	85.9	91.3	87.3	78.7	71.3	57.0	34.0	45.4
11.	Cost of service (excl, interest & return)	2,870.4	2,742.7	2,838.4	2,590.0	2,196.9	2,140.8	2,310.2	2,134.6

Witnesses: K. Culbert
R. Small

CME INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1, Tab 3, Schedule 1, page 4 of 29

At Table 2, EGD provides a comparison of the 2013 Test Year versus 2012 Bridge Year for other operating and maintenance expense by cost type. Please provide tables in the same format as Table 2, which provide the following additional comparisons:

(a) 2007 actuals versus the Board-approved 2007 budget;
(b) 2008 actuals versus 2007 actuals;
(c) 2009 actuals versus 2008 actuals;
(d) 2010 actuals versus 2009 actuals; and
(e) 2011 actuals versus 2010 actuals

For each of these reproduced tables, please provide a "variance explanation", which sets out the major drivers for significant increases or decreases in each table.

RESPONSE

a) The comparison between 2007 actuals versus the Board approved 2007 budget in this format cannot be reasonably performed due to the reason explained in Exhibit D1, Tab 3, Schedule 1, page 10, Paragraph 31.

b) 2008 Actual vs. 2007 Actual

The 2008 Other O&M actual is $197.0 million. This represents an increase of $1.0 million from 2007. The variances by cost type are summarized in Table 1. The key drivers are presented below.

Witnesses: S. Kancharla
R. Lei

Table 1
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2008 Actual vs. 2007 Actual

Line No.	Particulars ($ millions)	Actual 2008 (a)	Actual 2007 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$127.0	$127.1	($0.1)	-0.1%
2.	Benefits	22.0	24.4	(2.3)	-9.6%
3.	Short Term Incentive Program	19.1	20.1	(1.0)	-4.9%
4.	Employee Training and Development	2.7	2.0	0.7	36.8%
5.	Materials and Supplies	5.7	4.9	0.8	16.1%
6.	Outside Services	51.8	50.5	1.4	2.7%
7.	Regulatory Costs	5.8	8.8	(3.0)	-33.9%
8.	Consulting	4.8	2.5	2.2	87.2%
9.	Repairs and Maintenance	0.7	2.8	(2.2)	-76.5%
10.	Fleet	9.9	9.4	0.5	4.9%
11.	Rents and Leases	7.1	7.5	(0.4)	-5.4%
12.	Telecommunications	3.1	3.4	(0.3)	-8.6%
13.	Travel and Other Business Expenses	3.1	2.7	0.3	12.6%
14.	Memberships	2.5	2.5	0.1	3.1%
15.	Claims, Damages and Legal Fees	1.2	1.6	(0.4)	-23.3%
16.	Interest on Security Deposits	1.7	1.7	0.0	0.5%
17.	Provision for Uncollectibles	16.7	15.2	1.5	9.6%
18.	Consumers Gas Ltd Charges	0.4	0.4	0.1	14.5%
19.	Internal Allocations and Recoveries	(26.1)	(20.9)	(5.2)	24.8%
20.	Other	11.2	6.8	4.5	65.8%
21.	Subtotal	270.4	273.3	(2.9)	-1.1%
22.	Capitalization (A&G)	(21.6)	(21.2)	(0.4)	1.9%
23.	Capitalization	(51.8)	(53.8)	2.0	-3.7%
24.	Non-Utility Allocations	(2.1)	(2.5)	0.4	-16.0%
25.	Subtotal Net Utility O&M Expense	194.9	195.8	(0.9)	-0.5%
26.	Conservation Services	2.1	0.2	1.9	1006.6%
27.	Total Other Utility O&M Expense before Eliminations	197.0	196.0	1.0	0.5%
28.	Regulatory Eliminations				
29.	To eliminate Conservation Services	-	-	-	-
30.	Incremental O&M Allocated to Unregulated Storage	-	-	-	-
31.	Total Eliminations	-	-	-	-
				-	-
32.	Total Other Utility O&M Expense	$197.0	$196.0	$1.0	0.5%

Witnesses: S. Kancharla
R. Lei

Benefits (excluding Pensions) decreased by $2.3 million primarily due to lower extended medical costs, benefit payments, and FTE's relative to 2007.

Regulatory costs decreased by $3.0 million from 2007 as per EB-2007-0615 Board approved agreement to reduce the regulatory expenses by $3.0 million.

Consulting increased by $2.2 million mainly due to higher IT application support and Envision cost.

Repairs and Maintenance decreased by $2.2 million mainly as a result of the inventory optimization.

Provision for Uncollectibles increased by $1.5 million due to higher write-offs of receivables as a result of the weakening economy.

Internal Allocations and Recoveries had higher recoveries by $5.2 million primarily attributable to higher damage recoveries.

Other increased by $4.5 million due to the one-time amount in 2008 associated with the realignment of operating practices with the Company's strategy under IR.

c) 2009 Actual vs. 2008 Actual

The 2009 Other O&M actual is $201.5 million. This represents an increase of $4.5 million from 2008. The variances by cost type are summarized in Table 2. The key drivers are presented below.

Table 2
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2009 Actual vs. 2008 Actual

Line No.	Particulars ($ millions)	Actual 2009 (a)	Actual 2008 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$125.1	$127.0	($1.9)	-1.5%
2.	Benefits	22.8	22.0	0.7	3.3%
3.	Short Term Incentive Program	25.3	19.1	6.2	32.4%
4.	Employee Training and Development	3.0	2.7	0.3	10.2%
5.	Materials and Supplies	4.4	5.7	(1.3)	-23.0%
6.	Outside Services	55.7	51.8	3.8	7.4%
7.	Regulatory Costs	5.8	5.8	-	0.0%
8.	Consulting	3.7	4.8	(1.0)	-22.0%
9.	Repairs and Maintenance	2.0	0.7	1.3	199.7%
10.	Fleet	8.3	9.9	(1.5)	-15.5%
11.	Rents and Leases	6.5	7.1	(0.5)	-7.7%
12.	Telecommunications	3.4	3.1	0.3	9.1%
13.	Travel and Other Business Expenses	2.7	3.1	(0.4)	-13.2%
14.	Memberships	2.6	2.5	0.1	2.5%
15.	Claims, Damages and Legal Fees	2.0	1.2	0.8	64.9%
16.	Interest on Security Deposits	1.0	1.7	(0.7)	-40.5%
17.	Provision for Uncollectibles	17.8	16.7	1.2	7.0%
18.	Consumers Gas Ltd Charges	-	0.4	(0.4)	-100.0%
19.	Internal Allocations and Recoveries	(23.8)	(26.1)	2.3	-8.9%
20.	Other	5.1	11.2	(6.1)	-54.6%
21.	Subtotal	273.4	270.4	3.0	1.1%
22.	Capitalization (A&G)	(23.9)	(21.6)	(2.3)	10.7%
23.	Capitalization	(50.1)	(51.8)	1.7	-3.2%
24.	Non-Utility Allocations	(1.9)	(2.1)	0.2	-8.8%
25.	Subtotal Net Utility O&M Expense	197.5	194.9	2.6	1.3%
26.	Conservation Services	4.0	2.1	1.9	88.4%
27.	Total Other Utility O&M Expense before Eliminations	201.5	197.0	4.5	2.3%
28.	Regulatory Eliminations				
29.	To eliminate Conservation Services	-	-	-	
30.	Incremental O&M Allocated to Unregulated Storage	-	-	-	
31.	Total Eliminations	-	-	-	
32.	Total Other Utility O&M Expense	$201.5	$197.0	$4.5	2.3%

Witnesses: S. Kancharla
R. Lei

Salaries and Wages decreased by $1.9 million mostly resulting from lower FTEs.

Short Term Incentive Program increased by $6.2 million reflecting the Company's performance in 2009.

Outside Services increased by $3.8 million mainly due to higher IT maintenance and MXGI work.

Internal Allocation and Recoveries had lower recoveries by $2.3 largely attributable to lower vehicle and fuel costs.

Other decreased by $6.1 million mainly due to a one-time amount in 2008 that was non-recurring in 2009.

A&G capitalization had higher capitalization by $2.3 million due to higher employee related costs.

d) 2010 Actual vs. 2009 Actual

The 2010 Other O&M actual is $205.5 million. This represents an increase of $4.0 million from 2008. The variances by cost type are summarized in Table 3. The key drivers are presented below.

Table 3
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2010 Actual vs. 2009 Actual

Line No.	Particulars ($ millions)	Actual 2010 (a)	Actual 2009 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$133.8	$125.1	$8.7	7.0%
2.	Benefits	22.9	22.8	0.1	0.4%
3.	Short Term Incentive Program	19.7	25.3	(5.6)	-22.2%
4.	Employee Training and Development	2.9	3.0	(0.1)	-4.6%
5.	Materials and Supplies	5.1	4.4	0.7	15.6%
6.	Outside Services	60.8	55.7	5.1	9.2%
7.	Regulatory Costs	5.8	5.8	-	0.0%
8.	Consulting	6.4	3.7	2.6	71.3%
9.	Repairs and Maintenance	1.7	2.0	(0.2)	-11.6%
10.	Fleet	8.1	8.3	(0.2)	-2.5%
11.	Rents and Leases	5.7	6.5	(0.8)	-12.4%
12.	Telecommunications	3.5	3.4	0.1	3.8%
13.	Travel and Other Business Expenses	3.4	2.7	0.7	27.7%
14.	Memberships	3.6	2.6	1.0	39.7%
15.	Claims, Damages and Legal Fees	1.7	2.0	(0.3)	-16.8%
16.	Interest on Security Deposits	0.5	1.0	(0.5)	-51.7%
17.	Provision for Uncollectibles	11.5	17.8	(6.3)	-35.5%
18.	Consumers Gas Ltd Charges	-	-	-	
19.	Internal Allocations and Recoveries	(24.8)	(23.8)	(1.0)	4.1%
20.	Other	4.8	5.1	(0.3)	-5.1%
21.	Subtotal	277.1	273.4	3.7	1.4%
				-	
22.	Capitalization (A&G)	(24.3)	(23.9)	(0.4)	1.8%
23.	Capitalization	(52.6)	(50.1)	(2.5)	5.1%
24.	Non-Utility Allocations	(4.1)	(1.9)	(2.2)	115.2%
25.	Subtotal Net Utility O&M Expense	196.1	197.5	(1.4)	-0.7%
26.	Conservation Services	9.4	4.0	5.5	138.6%
27.	Total Other Utility O&M Expense before Eliminations	205.5	201.5	3.2	1.6%
28.	Regulatory Eliminations				
29.	To eliminate Conservation Services	-	-	-	
30.	Incremental O&M Allocated to Unregulated Storage	-	-	-	
31.	Total Eliminations	-	-	-	
				-	
32.	Total Other Utility O&M Expense	$205.5	$201.5	$4.0	2.0%

Witnesses: S. Kancharla
R. Lei

Salaries are higher by $8.7 million primarily due to higher FTEs and merit increases.

STIP decreased $5.6 million as a reflection of Company performance.

Outside Services increased by $5.1 million primarily as a result of higher contractor costs. The costs were in relation to higher sewer laterals, increased safety spending, and leak and corrosion costs.

Consulting increased by $2.6 million largely due to higher technical training costs and incremental application support.

Provision for uncollectibles decreased by $6.3 million.

Conservation service costs were higher by $5.5 million due to higher incentives, staff additions, as well as higher program and consulting costs driven by higher activities. These increases were offset by the corresponding revenue. Starting in 2011, the conservation service program has its own sharing mechanism, as approved by the Board in EB-2011-0008. Thus, conservation service costs along with its revenues are eliminated from the Company's net income in 2011 and onwards.

e) 2011 Actual vs 2010 Actual

The 2011 Other O&M actual is $224.7 million. This represents an increase of $19.2 million from 2009. The variances by cost type are summarized in Table 4. The key drivers are presented below.

Table 4
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Cost Type
2011 Actual vs. 2010 Actual

Line No.	Particulars ($ millions)	Actual 2011 (a)	Actual 2010 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$141.5	$133.8	$7.7	5.7%
2.	Benefits	24.3	22.9	1.4	6.1%
3.	Short Term Incentive Program	25.2	19.7	5.5	28.1%
4.	Employee Training and Development	5.6	2.9	2.7	95.0%
5.	Materials and Supplies	5.2	5.1	0.1	2.8%
6.	Outside Services	63.2	60.8	2.4	4.0%
7.	Regulatory Costs	4.8	5.8	(1.0)	-17.4%
8.	Consulting	5.0	6.4	(1.3)	-21.0%
9.	Repairs and Maintenance	1.4	1.7	(0.4)	-20.6%
10.	Fleet	9.0	8.1	0.9	10.8%
11.	Rents and Leases	7.3	5.7	1.6	27.5%
12.	Telecommunications	3.1	3.5	(0.4)	-10.8%
13.	Travel and Other Business Expenses	3.5	3.4	0.1	3.5%
14.	Memberships	4.0	3.6	0.4	10.0%
15.	Claims, Damages and Legal Fees	1.6	1.7	(0.1)	-4.0%
16.	Interest on Security Deposits	1.0	0.5	0.5	109.0%
17.	Provision for Uncollectibles	21.5	11.5	10.0	87.3%
18.	Consumers Gas Ltd Charges	-	-	-	
19.	Internal Allocations and Recoveries	(25.7)	(24.8)	(1.0)	3.9%
20.	Other	8.0	4.8	3.2	65.2%
21.	Subtotal	309.5	277.1	32.4	11.7%
				-	
22.	Capitalization (A&G)	(24.5)	(24.3)	(0.2)	0.6%
23.	Capitalization	(55.3)	(52.6)	(2.6)	5.0%
24.	Non-Utility Allocations	(4.9)	(4.1)	(0.8)	20.3%
25.	Subtotal Net Utility O&M Expense	224.9	196.1	28.8	14.7%
26.	Conservation Services	7.3	9.4	(2.1)	-22.7%
27.	Total Other Utility O&M Expense before Eliminations	232.2	205.5	26.7	13.0%
28.	Regulatory Eliminations				
29.	To eliminate Conservation Services	(7.3)	-	(7.3)	-
30.	Incremental O&M Allocated to Unregulated Storage	(0.2)	-	(0.2)	-
31.	Total Eliminations	(7.5)	-	(7.5)	-
				-	
32.	Total Other Utility O&M Expense	$224.7	$205.5	$19.2	9.3%

Witnesses: S. Kancharla
R. Lei

Salaries are higher by $7.7 million primarily due to higher FTEs and merit increases.

STIP increased $5.5 million as a reflection of Company performance.

Employee Training and Development increased by $2.7 million primarily attributable to higher leadership training and relocation costs.

Outside Services increased by $2.4 million mainly resulting from higher sewer laterals and damage prevention costs.

Provision for Uncollectibles increased by $10.0 million.

Other increased by $3.2 million mainly as a result of higher donations and sponsorships.

Conservation Services is lower by $2.1 million due to lower spending. For the purposes of ESM, conservation services are eliminated for utility O&M calculation starting in 2011 since there is a separate sharing mechanism as per Settlement Agreement on EB-2011-0008.

Witnesses: S. Kancharla
R. Lei

CME INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1, Tab 3, Schedule 1, page 4 of 29

In preparing the variance explanation requested above, please identify items that represent efficiency or productivity gains, and whether that productivity or efficiency gain continued in the following years. For those productivity or efficiency gains which only existed during the IRM period, please provide an explanation as to why they will not continue in 2013 and beyond.

RESPONSE

Please see the response to CCC Interrogatory #2, filed at Exhibit I, Tab O3, Schedule 5.2 for a presentation of activities that resulted in cost reductions during the IR plan.

Witnesses: S. Kancharla
R. Lei
M. Lister

CME INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1, Tab 3, Schedule 1, page 12 or 29, Table 5

At Table 5, EGD provides a summary of Full-Time Equivalents ("FTEs") for 2013 budget, 2012 estimate, 2011 historical and 2007 Board-approved. Please broaden this Table to include actual amounts for 2007, 2008, 2009 and 2010.

RESPONSE

Please see the response to the Board Staff Interrogatory #5 at Exhibit I, Issue D1, Schedule 1.5.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

CME INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1, Tab 3, Schedule 1, page 14 of 29, Table 6

At Table 6, EGD sets out the O&M expense on a cost per customer basis. We note that for the years 2008, 2009, 2010 and 2011 the utility O&M cost per customer is less than in 2007 and increases dramatically in 2012. We wish to better understand the reduction in utility O&M cost per customer during this time period. To this end, please provide the following information:

(a) Identify all productivity or efficiency gains achieved in 2008, 2009, 2010 and 2011 which resulted in a reduction of utility O&M cost per customer;

(b) Are there reasons in addition to the productivity or efficiency gains set out in subparagraph (a) above, which contributed to the reduction O&M cost per customer in the years 2008, 2009, 2010 and 2011?

(c) Please identify which efficiency or productivity gains set out in subparagraph (a) above are expected to continue beyond 2011;

(d) Please identify which efficiency or productivity gains do not continue beyond 2011, and provide an explanation for why these were temporary only during the IRM period.

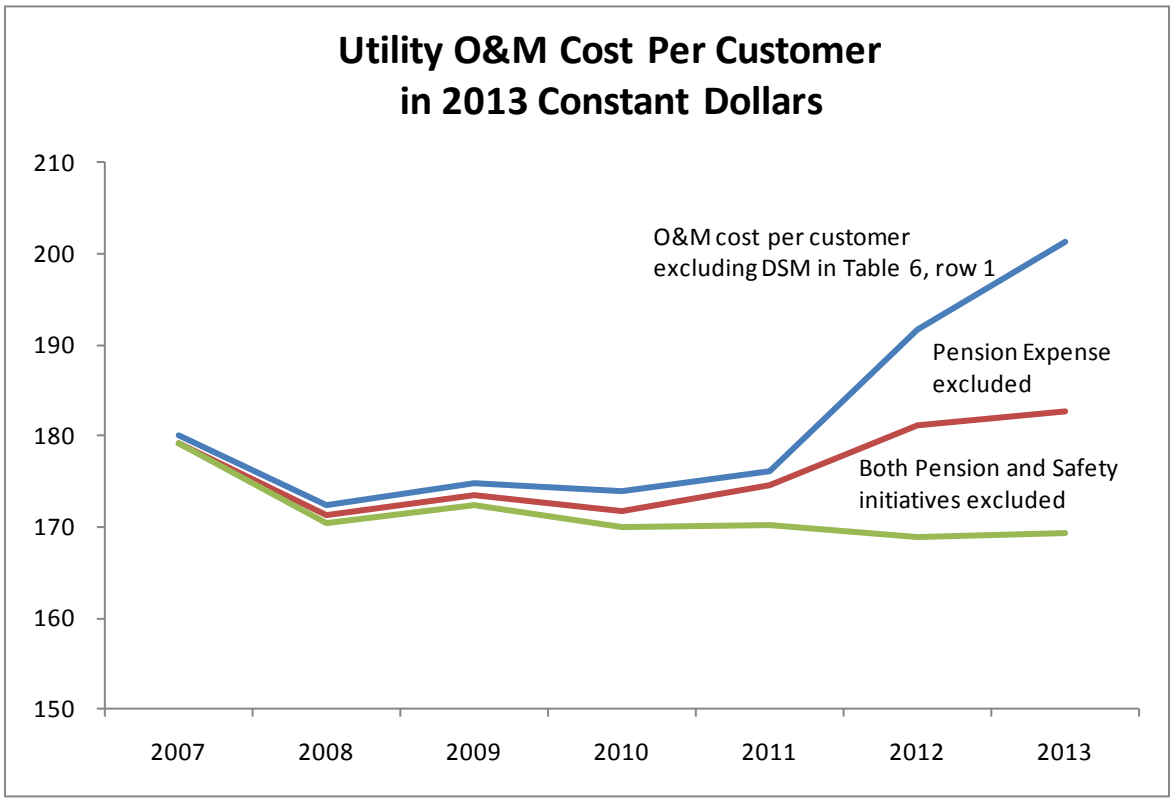
RESPONSE

a) Please see the response to CCC Interrogatory #2, filed at Exhibit I, Tab O3, Schedule 5.2 for a presentation of activities that resulted in cost reductions during the IR plan.

b) There are two primary reasons contributing to higher O&M cost per customer in 2012 and 2013 relative to 2008 to 2011: pension expense, and incremental safety

Witnesses: R. Fischer
S. Kancharla
R. Lei
M. Lister
S. Trozzi

and integrity spending. Excluding these two costs, the reduction in O&M cost per customer will continue in 2012 and 2013, as demonstrated in the following chart.



Pension expense increase is the key reason for the significant increase of O&M cost per customer in 2012 and 2013. Pension expense is a fixed cost primarily driven by external factors the Company has limited ability to influence. The average annual growth for pension expense for 2012 and 2013 is 310% compared to 25% increase for the previous four years. In 2007, pension expense accounted for 0.5% of total utility O&M expenses. In 2013, pension expense accounts for 8.5% of total O&M expenses. The reasons for pension expenses are discussed separately in interrogatory responses related to Issue D4.

Another major reason for the increase is the extra costs resulting from incremental safety and integrity initiatives the Company must undertake in 2012 and 2013. The Company has placed greater emphasis on safety and integrity of pipelines to minimize risks associated with the worker and public safety and to comply with legal

Witnesses: R. Fischer
S. Kancharla
R. Lei
M. Lister
S. Trozzi

and regulatory requirements and meet industry best practices. These incremental costs are over and above the historical business as usual levels.

c) Please see the response to CCC Interrogatory #2 filed at Exhibit I, Tab O3, Schedule 5.2.

d) Please see the response to CCC Interrogatory #2 filed at Exhibit I, Tab O3, Schedule 5.2.

Witnesses: R. Fischer
S. Kancharla
R. Lei
M. Lister
S. Trozzi

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: A2/T1/S1/p. 17

The evidence states that the inflation adjusted O&M cost per customer are virtually unchanged since 2004. The table provide indicates, however, that during the IRM term the cost per customer was well below the 2013 amount. Please explain why the 2013 O&M cost per customer is significantly above the O&M cost per customer in 2007, 2008, 2009, 2010 and 2011.

RESPONSE

Please see the response to Board Staff Interrogatory #16 at Exhibit I, Issue D1, Schedule 1.16 b) and c).

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: A2/T1/S1/p. 25

The evidence states that Enbridge has the fifth lowest O&M cost per customer amongst the Concentric peer group. How was the peer group chosen? To what extent was density considered in the study when the comparisons were made?

RESPONSE

As discussed at Exhibit A2, Tab 1, Schedule 2, page 2, the peer group was chosen based on similarity of operations to EGD (natural gas distribution utilities or combination utilities with data for natural gas distribution operations available separately from electric operations), similarity of weather conditions to EGD (located in the northern half of the U.S.), similarity of size to EGD (at least 500,000 customers in a single state), and data availability. Density for EGD and the peer group was discussed at Exhibit A2, Tab 1, Schedule 2, pages 12 to14.

Customer density, measured in terms of customers per mile of distribution main, does not have a significant impact on O&M cost per customer. That is, Enbridge's low ranking in O&M cost per customer (Exhibit A2, Tab 1, Schedule 2, page 21) is not the result of its high ranking in customer density (Exhibit A2, Tab 1, Schedule 2, pages 14 and 15).

Witnesses: M. Lister
J. Coyne
M. Bartos
J. Simpson
Concentric

CCC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 1

The evidence states that the O&M budget was reviewed and approved by the EMT. Please provide a detailed list of any changes to the proposed budget that were made by the EMT. Please explain the reasons for each of those changes.

RESPONSE

Since the budget is developed on a grass-roots basis, each department is required to prepare a budget which ties in to the Company's objectives and follows the Budget Assumptions and Guidelines Directive ("the Budget Directive") produced at Exhibit A2, Tab 2, Schedule 1. In an effort to improve the budget process by minimizing budget iterations, the Budget Directive was enhanced for purposes of the 2013 Budget by providing more comprehensive and specific guidance to departments to ensure better alignment.

While the EMT was involved in the development of the Budget Directive, individual EMT members are engaged in the budget process from start to finish and their directions and recommendations are progressively incorporated into the departmental budgets for which they have responsibility. As such, most changes are factored in the departmental budget before it is consolidated by Finance. The budget review with the EMT is characterized by three phases during the budget cycle:

1. Departments hold internal reviews with their respective EMT members.
2. Finance has a one-on-one budget review with departments and their respective EMT members.
3. Finance consolidates the budget for the EMT review.

Prior to the consolidated budget in phase 3, the budget by department is a work-in-progress draft which undergoes multiple on-going iterations which make version tracking administratively impossible. Recommendations brought up during the budget

Witnesses: S. Kancharla
R. Lei

review are mostly done verbally, which are subsequently reflected in the budget by department and validated by Finance.

Once departments reflect changes from the review in phase 2, Finance validates and consolidates the Company-wide budget for the EMT review. If there are no further changes from the review, the budget is then finalized. The 2013 budget presented to the EMT for review is described in the presentations attached to the response to SEC Interrogatory #5 at Exhibit I, Issue D1, Schedule 14.5.

Following the EMT review of the 2013 budget in September 2011, there were two changes to the budget. First, in late 2011, there was an update to a number of system integrity costs, which increased the O&M budget. Second, as described at Exhibit D1, Tab 3, Schedule 1 updated June 1, 2012, page 25, Paragraph 2, due to RCAM (to reflect MNP recommendations), DSM and a pension increase (to reflect a more current estimate) which was partially offset by an increase in the amount of overheads capitalized.

The following table represents the sequence of O&M budget changes from the initial consolidated budget.

Enbridge Gas Distribution
2013 O&M Budget Changes

Line No.	Categories ($ Millions)	Col. 1 Initial Budget 2013	Col. 2 Integrity Cost Update	Col. 3 Budget 2013	Col. 4 Other Updates June 2012	Col. 5 Updated Budget 2013
1.	Customer Care Service Charges	$89.4		$89.4		$89.4
2.	RCAM	30.3		30.3	1.8	32.1
3.	DSM	28.6		28.6	2.8	31.4
4.	Pension Expense	27.7		27.7	9.6	37.3
5.	Other O&M	237.5	12.6	250.1	(2.2)	247.9
6.	Total Net Utility O&M Expense	$413.5	$12.6	$426.1	$12.0	$438.1

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 2

Please re-cast Table 1 to include 2007-2010 actuals.

RESPONSE

Table 1
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2013 Budget, 2012 Estimate, 2011-2007 Actual, and 2007 Board Approved

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.	Categories ($ Millions)	Budget 2013	Estimate 2012	Actual 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007	Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$79.2	$87.5	$87.5	$82.5	$84.4	$90.8
2.	Regulatory Cost Allocation Methodology(RCAM)	32.1	30.2	26.7	24.3	21.2	19.1	18.1	18.1
3.	Demand Side Management (DSM)	31.4	28.1	26.7	25.5	24.3	23.1	22.0	22.0
4.	Pension Expense	37.3	20.6	3.2	4.0	2.6	1.7	1.5	1.7
5.	Other O&M	247.8	232.9	224.7	205.5	201.5	197.0	196.0	193.6
6.	Total Net Utility O&M Expense	$438.1	$402.2	$360.5	$346.7	$337.0	$323.4	$322.0	$326.2

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 4

Please re-cast Table 2 (Other Operating and Maintenance Expense by Cost Type) to include 2007 actual and Board approved and actuals for 2008-2011.

RESPONSE

Please see the table on the following page.

Witnesses: S. Kancharla
R. Lei

Table 2
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Category
2013 Budget, 2012 Estimate, 2011-2007 Actual, and 2007 Board Approved

Line No.	Particulars ($ millions)	Col. 1 Budget 2013	Col. 2 Estimate 2012	Col. 3 Actual 2011	Col. 4 Actual 2010	Col. 5 Actual 2009	Col. 6 Actual 2008	Col. 7 Actual 2007	Col. 8 Board Approved 2007*
1.	Salaries and Wages	$170.9	$160.7	$141.5	$133.8	$125.1	$127.0	$127.1	$136.5
2.	Benefits	30.5	25.9	24.3	22.9	22.8	22.0	24.4	21.3
3.	Short Term Incentive Program	20.3	19.4	25.2	19.7	25.3	19.1	20.1	14.7
4.	Employee Training and Development	4.1	4.0	5.6	2.9	3.0	2.7	2.0	3.3
5.	Materials and Supplies	5.5	5.5	5.2	5.1	4.4	5.7	4.9	9.0
6.	Outside Services	79.0	77.9	63.2	60.8	55.7	51.8	50.5	56.2
7.	Regulatory Costs	7.3	5.8	4.8	5.8	5.8	5.8	8.8	7.6
8.	Consulting	9.5	6.7	5.0	6.4	3.7	4.8	2.5	4.8
9.	Repairs and Maintenance	2.0	1.9	1.4	1.7	2.0	0.7	2.8	1.2
10.	Fleet	10.0	9.8	9.0	8.1	8.3	9.9	9.4	10.5
11.	Rents and Leases	7.7	7.4	7.3	5.7	6.5	7.1	7.5	9.0
12.	Telecommunications	3.7	3.6	3.1	3.5	3.4	3.1	3.4	3.6
13.	Travel and Other Business Expenses	4.9	4.7	3.5	3.4	2.7	3.1	2.7	4.0
14.	Memberships	3.4	3.2	4.0	3.6	2.6	2.5	2.5	2.9
15.	Claims, Damages and Legal Fees	0.8	0.8	1.6	1.7	2.0	1.2	1.6	1.5
16.	Interest on Security Deposits	2.7	1.9	1.0	0.5	1.0	1.7	1.7	1.7
17.	Provision for Uncollectibles	15.2	13.7	21.5	11.5	17.8	16.7	15.2	15.1
18.	Consumers Gas Ltd Charges	-	-	-	-	-	0.4	0.4	0.4
19.	Internal Allocations and Recoveries	(25.3)	(25.1)	(25.7)	(24.8)	(23.8)	(26.1)	(20.9)	(17.2)
20.	Other	7.2	5.9	8.0	4.8	5.1	11.2	6.8	7.0
21.	Subtotal	359.3	333.8	309.5	277.1	273.4	270.4	273.3	293.0
22.	Capitalization (A&G)	(37.7)	(31.4)	(24.5)	(24.3)	(23.9)	(21.6)	(21.2)	(19.1)
23.	Capitalization	(69.2)	(65.3)	(55.3)	(52.6)	(50.1)	(51.8)	(53.8)	(57.6)
24.	Non-Utility Allocations	(3.4)	(3.2)	(4.9)	(4.1)	(1.9)	(2.1)	(2.5)	(22.7)
25.	Subtotal Net Utility O&M Expense	249.0	233.9	224.9	196.1	197.5	194.9	195.8	193.6
26.	Conservation Services	1.5	7.0	7.3	9.4	4.0	2.1	0.2	-
27.	Total Other Utility O&M Expense before Eliminations	250.5	240.9	232.2	205.5	201.5	197.0	196.0	193.6
28.	Regulatory Eliminations								
29.	To eliminate Conservation Services	(2.5)	(7.9)	(7.3)	-	-	-	-	-
30.	Incremental O&M Allocated to Unregulated Storage	(0.2)	-	(0.2)	-	-	-	-	-
31.	Total Eliminations	(2.7)	(7.9)	(7.5)	-	-	-	-	-
32.	Total Other Utility O&M Expense	$247.8	$232.9	$224.7	$205.5	$201.5	$197.0	$196.0	$193.6

* The reduction in the 2007 Decision is not prorated by cost type but rather grouped in Non-utility Allocations (Line No. 24)

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 6

The evidence states that there is an increase in 2013 in consulting costs primarily related to incremental services required to achieve the Company's goal of zero safety incidents through the Path to Zero initiative. Please explain, in detail the nature of these costs.

RESPONSE

An assessment of Enbridge's safety management systems conducted in 2010 identified cultural and systemic gaps that are hindering Enbridge's attainment of the Path to Zero initiative. Improvement areas to achieve the goal include:

- Establishing an integrated organization to manage key safety related processes
- Establishing a comprehensive risk management system
- Improving contractor safety
- Improving environment, health and safety programs.

Building a strong safety culture, organization, metrics and auditing are key to sustaining process safety and operational excellence. Operational effectiveness is a function of standards and the level of execution of those standards. Strong leadership through visible and demonstrated commitment, clear and meaningful policies and principles, challenging goals and plans and high standards of performance is required to ensure a strong safety culture which will support operational excellence.

Employee Safety was moved from two Process Improvement Teams to four Process Improvement Teams.

Distribution Safety was increased from two Process Improvement Teams to eleven Process Improvement Teams.

Witnesses: J. Briggs
C. Hanlon
S. Kancharla
R. Lei

Training will continue to be provided to all people leaders on key concepts of safety leadership in an expedited manner to support the execution of the safety management system and the Path to Zero Initiative.

DuPont Sustainable Solutions ("DSS") has been retained since 2010. The Consultants will continue to:

- Develop templates for key processes and standards to expedite the completion of activities
- Conduct specified audits
- Develop and deliver specified training
- Leverage business process reengineering tools to expedite the development of Enbridge processes
- Coach the organization on implementing and managing safety systems

Witnesses: J. Briggs
C. Hanlon
S. Kancharla
R. Lei

CCC INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 4

Please provide a detailed breakdown of the $9.5 million in Consulting costs for 2013.

RESPONSE

The following is a breakdown of the $9.5 million in consulting costs for 2013

$Millions	Budget 2013
1. Path to Zero initiative for improved public, contractor and worker safety	$ 3.3
2. Consulting for Envision STORMS upgrade	1.8
3. IT consulting	1.0
4. Material and course program Development for Technical Training initiative	0.8
5. Employee services and facilities related consulting	0.6
6. Customer and government related public relations consulting cost	0.4
7. Consulting with third parties	1.8
	$ 9.5

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 4

Please provide a detailed budget for "Outside Services" for 2011, 2012 and 2013. Please explain the nature of each budget item and an explanation as to why those services are required.

RESPONSE

EGD requires the use of external contractors to perform services required to directly or indirectly deliver customer services. These services may include new initiatives/projects, maintenance, upgrades, or compliance. The table below highlights the contractor services for the three years.

Enbridge Gas Distribution
Outside Services Details
2013 Budget, 2012 Estimate, 2011 Actual

$ Millions	Why it is required	Budget 2013	Estimate 2012	Actual 2011
1. Service Contractors	Provide services to support directly or indirectly customer deliverables	$ 54.6	$ 56.0	$ 42.0
2. Legal services	Provide legal support, records management services and field assessments	0.2	0.2	0.1
4. Customer requested gas pipe location	To avoid pipeline damages and incidents	14.8	13.7	14.6
5. In line inspection for defects in high stress pipelines	Mandated initiative	3.1	2.1	0.5
6. Employee Services	Provide support to employees	0.5	0.5	0.5
7. Facilities Services	Provide facilities support including maintenance, security, rents and leases	5.8	5.3	5.5
8. Total		$ 79.0	$ 77.9	$ 63.2

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 4

Please provide a detailed budget for "Travel and Other Business Expenses" for 2011, 2012 and 2013. In addition, please file the actual amounts for 2007-2010 for this cost item. Please provide all internal guidelines relevant to this budget item.

RESPONSE

The Travel and Other Business Expenses would include amounts related to airfare costs, accommodations, meals, transportation, conferences and other travel related expenses.

Please see all internal guidelines in the attachment.

	Budget	Estimate	Actual	Actual	Actual	Actual	Actual
$ Millions	2013	2012	2011	2010	2009	2008	2007
1. Airfare	$1.2	$1.2	$0.7	$0.6	$0.3	$0.6	$0.3
2. Ground transportation	0.8	0.8	0.7	0.7	0.6	0.7	0.6
3. Accommodation	1.1	1.0	0.8	0.7	0.6	0.7	0.6
4. Meals and entertainment	1.3	1.3	1.3	1.2	1.1	1.1	1.1
5. Other travel expense	0.1	0.1	0.1	0.1	0.2	0.1	0.1
6. Conference and registration fees	0.7	0.7	0.5	0.8	0.4	0.5	0.4
7. Total	$5.3	$5.2	$4.0	$4.0	$3.2	$3.7	$3.1

Witnesses: S. Kancharla
R. Lei

Corporate Policy

ENBRIDGE

Subject: *Employee Business Expenses*	Date Issued: *April 2002*	Section: *4.3.6*
Issued by: *Corporate Administration*	Date Revised: *November 24, 2009*	Page: *1 of 12*

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ENBRIDGE

Subject: *Employee Business Expenses*	Date Issued: *April 2002*	Section: *4.3.6*
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1.0 Statement of Purpose

This Employee Business Expense Policy ("Policy") applies to employees of Enbridge Inc. (the "Company"), its subsidiaries and legal entities including Company-operated equity investees, joint ventures and partnerships (collectively, "Enbridge"). It acknowledges that Enbridge management is responsible for establishing the framework and principles within which levels of control and accountability over employee business expenses are managed.

Employees are expected to follow the principles contained in the Policy when circumstances require their presence in other locations for the conduct of Enbridge's business.

The purpose of this Policy is to provide levels of authority and responsibility for managing employee business expenses and to identify expenses of a personal nature not normally paid by Enbridge.

Compliance with this Policy is mandatory. Failure to strictly comply with this Policy may result in disciplinary action, up to and including termination of employment.

2.0 General

Employee business expenses are an integral part of the budgets and operating plans of the Company that are approved annually by its Board of Directors. They form a significant part of the Company's controllable cost structure and senior management considers containment and control of these costs to be important.

Enbridge pays for all reasonable and actual business expenses such as travel, accommodation, meals, business-related entertainment and associated incidental expenses incurred by employees during the conduct of Enbridge's business. Enbridge does **not** pay for personal expenses. All employees are expected to use good judgement and integrity in the interpretation of this Policy.

Enbridge provides for acceptable business standards of comfort, convenience, safety and security for employees engaged in business travel. Business travel should be arranged only in the event that Enbridge's business cannot be conducted through alternate means of communication, e.g., teleconferences, videoconferences and Internet meetings.

Matters related to the interpretation or clarification of this Policy, including suggestions for amendments should be referred to the Company's Manager, Corporate Administration or Vice President, Human Resources and Administration for consultation and advice. Matters that are or could be considered to be in contravention of the principles contained in this Policy must be brought to the attention of management and, as appropriate, to the Company's Vice President, Human Resources and Administration.

3.0 Authorization and Approval

Employee business travel must be authorized in advance by the employee's department manager. For business travel outside Canada and the United States, advance authorization of a Vice President is required. Advance authorization must also be obtained for situations requiring a departure from this

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Policy. Such situations are expected to be rare.

An employee's department manager or supervisor, in accordance with criteria established in the Company's Corporate Policy No. 1-101, "Authorities and Spending Limits", must approve employee business expense reports.

4.0 Employee Business Expense Management Controls

Corporate Credit Card Program

Enbridge's sole corporate business expense credit card program is with American Express Bank of Canada ("American Express"). The American Express credit card ("American Express card") must be used for all travel and entertainment expenses (air travel, ground transportation, accommodation, meals, entertainment and other related expenses).

Except in unusual circumstances, the Corporate American Express card must not be used for personal expenses.

American Express cards are issued, subject to Enbridge accepted and approved applications, to permanent employees having a demonstrated business need (i.e. those who regularly incur business expenses or who travel at least once a year).

Enbridge's contract with American Express provides for an "individual bill / Enbridge pay" arrangement. Under this arrangement, Enbridge is responsible and liable for timely settlement of all approved charges owing on the American Express card. Employees are responsible for prompt settlement of unapproved and personal charges.

Enbridge regularly monitors employee use of American Express cards, especially as to timely settlement of cash advances and outstanding account balances. If an employee incurs delinquency charges on their American Express card, the employee **is** personally responsible for payment of those charges to American Express.

In addition to the foregoing, Enbridge's Business Units, legal entities and Corporate Office should be aware of the following principles when issuing American Express cards to employees:

- Employees may use the American Express card to obtain cash advances, for business purposes only, from Automated Teller Machines;
- Enbridge authorizes daily and monthly limits for American Express card cash advances, dependent upon business needs, and does **not** provide travel advances to employees;
- Subject to advance authorization, employees may use the American Express card to charge professional dues, licenses, membership fees and technical and general business publications necessary for the conduct of Enbridge business;
- Registration in the American Express rewards program is no longer available to card holders; Employees currently in the program are responsible for the ongoing annual costs, including costs associated with taxable benefits arising from the program; and
- Enbridge, at its sole discretion, may block use of the American Express card at individual merchants, groups of merchants, types of merchants or any combination thereof.

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Preferred Suppliers

Enbridge has contracted several preferred suppliers for air travel, ground transportation and accommodation services and has obtained favourable pricing structures under these contracts. Use of preferred suppliers by employees for business expenses ensures that Enbridge obtains economic benefit.

Travel Arrangements

All Enbridge individual, group and meeting reservations for air travel, ground transportation and accommodation, including any subsequent or *en route* change, must be arranged with Enbridge's contracted travel agency, American Express Business Travel ("American Express Travel"). American Express Travel has been instructed to patronize Enbridge's preferred suppliers unless those suppliers are unable to meet requested arrangements or a specific business purpose warrants otherwise. In those situations, which are expected to be rare, American Express Travel will propose acceptable alternate arrangements. Enbridge will **not** pay for travel arrangements made by employees other than through the offices of American Express Travel unless such arrangements are unavoidable.

When making business travel arrangements, employees of Enbridge's Business Units, legal entities and Corporate Office must be aware of the following:

Air Travel

- American Express Travel, in consultation with employees, is instructed to reserve the Lowest Logical Fare available with respect to airfare, hotels and car rentals;
- Employees Director level and above may choose to travel Business Class for flights within North America that are in excess of three (3) hours.
- Business Class travel is permitted on International flights outside of Canada and the United States;
- Employees are encouraged to consider excursion fares or Saturday night stays in order to realize further cost reductions (Enbridge will reimburse additional accommodation and meal costs where the airfare savings exceed those additional costs);
- A Company-paid account for employees **not** having an American Express card must be used, subject to prior authorization from the Company's Manager, Corporate Administration, for employees who have infrequent need of air travel; and
- Unused or partially used air travel tickets, particularly e-tickets, must be returned immediately to American Express Travel for credit.

Ground Transportation

- Employees are expected to instruct American Express Travel to reserve ground transportation with Enbridge's preferred suppliers;
- In the event other means of ground transportation are unavailable, impractical or more costly, only moderately priced, mid-sized economy cars should be rented;
- In Canada and the United States, optional rental car insurances should be declined when car rentals are charged to the Corporate American Express card;
- Employees renting cars outside Canada and the United States must be aware of the terms and conditions of rental agreements in order to avoid unnecessary charges and obligations or deprive Enbridge of its insurance and liability protection, and should accept optional collision and theft

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 5.9, Attachment, Page 4 of 21

insurances and decline third party liability coverage;
- Rental cars should be refueled before being returned to the rental agency;
- Employees are encouraged to limit use of taxis to situations where more economical or public transportation is unavailable; and
- Subject to prior authorization and in limited circumstances, personal vehicles may be used for business travel (employees may submit an expense claim using their Enbridge Business Unit's currently approved mileage rate).

Accommodation
- Employees are expected to reserve accommodation with Enbridge's preferred suppliers; and
- First night accommodation reservations are guaranteed when charged to an American Express card. Travelers will be advised by American Express when making the reservation as to the cancellation policy respecting the hotel they are booking.

Group Travel
- Travel arrangements for Enbridge personnel that involve ten (10) or more participants must be specifically identified to American Express Travel, in advance, in order for Enbridge to obtain benefit from contractually negotiated group discounts.

5.0 Business Expenses

Employee business expenses must be reasonable and incurred in the conduct of Enbridge business. Reasonable expenses are considered those that are appropriate for the nature of the business being conducted. Prudent judgment requires a conservative interpretation of the validity and reasonableness of business expenses. Business expenses must be incurred directly by the employee submitting an expense report.

Oracle Internet Expenses ("iExpense") is the enterprise on-line expense reporting system and must be used by all employees when submitting employee business expenses. Employees incurring business expenses must request access through their Local Help Desk. All Enbridge AP Departments will reject any other form of employee business expense claim.

Original and valid receipts for all expense claims must be provided wherever possible. It is company policy to obtain and submit receipts for all expense amounts. However, for expenditures less than **$25** and where it is not practicable to obtain a receipt, a receipt does not need to be submitted. In these limited circumstances, the preparer must check the "Receipt Missing" box in iExpense for the particular expense. This may be subject to review for reasonableness of application. All receipts must accompany the employee's expense report.

Airfare, Ground Transportation and Accommodation

Enbridge pays the actual cost of airfare, ground transportation and accommodation, including surcharges, usage fees and non-refundable taxes and levies associated with the conduct of its business.

Meals

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Enbridge pays the actual cost, including reasonable gratuity, of meals associated with the conduct of its business. This includes in-town meals, out-of-town meals and meals associated with offsite seminars, courses and meetings. A meal including the employee and others is to be indicated as a "Business Meal" in iExpense, while a meal including only the employee must be indicated as an "Individual Meal" in iExpense.

As a general guideline, a reasonable gratuity for good service in certain types of restaurants would be 15%. Service quality is a significant criteria for any additional amount added for gratuity.

All Business meal expenses must be incurred by the most senior ranking person hosting the business meal and must include in iExpense at least the first initial and last name of all participants in that meal (in the "Attendee" field) and the business purpose of the meal (in the "Justification" field).

Business Entertainment

Enbridge pays reasonable entertainment expenses (for example, shows and sporting events) incurred in conjunction with an Enbridge business activity for clients, customers, prospective customers and business associates. In the event more than one Enbridge employee is involved in the business entertainment function, the most senior ranking employee must incur the expense.

In a situation where a department is hosting an event and other departments may be included, the most senior ranking person of the hosting department shall incur the expense.

Personal Communications Devices

Enbridge pays business related operating expenses of personal communication devices owned by employees. Enbridge does not normally pay monthly access and minimum usage charges.

For greater certainty, all data, voice and other charges resulting from using the Bring Your Own Device ("BYOD") service are your sole responsibility. While this policy and others deal with claiming certain business related expenses, you shall not be entitled to reimbursement from Enbridge for your monthly fees, voice, data, overage or other charges merely as a result of connecting your personal mobile device to the BYOD service.

Internet Charges

Enbridge pays business related Internet portal connection and usage charges when those charges are incurred in conjunction with out-of-town travel, e.g., from an airport or hotel.

Telephone Calls

Enbridge pays business related telephone operating expenses. Employees should use Enbridge calling cards for all long distance calls, particularly on airlines, cell phones and from hotel rooms to minimize toll charges. Usage of airline, railway and rental car phone systems should be kept to a minimum due to high toll charges. (Enbridge US business locations do not utilize calling cards.)

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 5.9, Attachment, Page 6 of 21

Incidentals

Enbridge will pay for incidental or sundry out-of-town business expenses when travel exceeds four (4) days (e.g. laundry and valet services).

Temporary Employees, Contractors, Consultants, Professional Advisors and Third Parties

Except where more economical, all parties reimbursed for business expenses while providing services to Enbridge, unless alternate contractual arrangements have been negotiated, shall follow this policy.

Corporate credit cards will not be provided to these individuals; however, they are expected to use Enbridge's preferred suppliers when incurring business expenses. If contractors are travelling on Enbridge business, and there is a financial advantage to book through the Enbridge suppliers, then the contractor can be set up on the Airline Billing Account (ABA). This account can be requested from the AMEX agent. The ABA card requires approval by the Manager of Corporate Administration. The appropriate account coding is required at time of booking.

Spousal Expenses

A Group Vice President or Executive Vice President must authorize, in advance, all eligible expenses for an employee's spouse for attendance at business related conferences and at other functions involving the active conduct of Enbridge business. Employees must demonstrate that spousal attendance is essential and directly related to the effective accomplishment of Enbridge's business.

6.0 Non-Paid Expenses

The following listed items, which are not all-inclusive, are **not** normally paid by Enbridge on behalf of employees engaged in business travel, unless specifically authorized in advance by a department manager:

- Purchase or lease cost of personal communication devices, including laptop computers;
- Personal effects and personal purchases;
- Dependent care;
- Airline club dues;
- Fines;
- Hotel cancellation charges;
- Optional flight and medical insurance;
- Damage to or loss of personal luggage, briefcases or vehicles, including any subsequent insurance premium increases;
- Rental car GPS access charges; and,
- Reciprocal employee entertainment.

7.0 Business Expense Documentation

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 5.9, Attachment, Page 7 of 21

ENBRIDGE

Subject: ***Employee Business Expenses***	Date Issued: ***April 2002***	Section: ***4.3.6***
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All business expenses submitted by employees must be itemized on an expense report contained in iExpense. The expense report must include a description of the purpose of the expense and be supported by original invoices, credit card charge records and receipts. Other documentary evidence indicating proof of payment for the business expense may be required to clearly show the nature of the expense and the confirmation that the payment was made by the employee.

Expense reports for business meals and entertainment of others must include:

- The business purpose for the expense;
- The name and business affiliation of those being met with or entertained;
- Original invoices, credit card charge records, and receipts that clearly show the name and address of the business establishment, the date and amount of charges, with separate identification of goods and services (including, in Canada, the GST registration number that must be clearly identifiable), provincial, state, municipal and local taxes.

The following table sets out the basic documentation required for each listed expense:

Expense	Required Documentation
Airfare	Original itinerary with invoice
Airfare Change Fees	Copy of American Express statement and/or invoice
American Express Credits	Copy of American Express and/or invoice
Accommodation	Hotel bill or folio
Helicopter Rental	Bill and/or invoice clearly indicating in the description field in iExpense the first initial and last name of each participant along with purpose of rental and business reason. Most senior Enbridge employee at the event must incur the expense.
Car Rental	Car rental invoice
Personal Vehicle	All parking and toll receipts
Business Meals	American Express charge card record and cash register receipt (clearly indicating in the "Attendee" field on Detail screen in iExpense the first initial and last name of each participant)
Entertainment	American Express charge card record and cash register receipt
Telephone, Fax, Cellular	Communication bills, Enbridge calling card bill, or cell phone statement of account
Other Transportation	American Express charge card record or cash register receipt
Out of Policy Exceptions	Written explanation in the "Justification" field in iExpense or appropriate documentation of expenses signed by the individual providing approval

Expense reports should not contain amounts pertaining to the individual providing approval.

Tear tab receipts are not accepted as supporting documentation for meals and entertainment expenses.

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 5.9, Attachment, Page 8 of 21

Except in unusual circumstances, Enbridge does not accept American Express card statements in lieu of original American Express card charge records as supporting documentation of business expenses incurred by employees.

Enbridge does not accept American Express Travel invoices as the only supporting documentation of employee air travel expenses or credit card receipts as the only supporting documentation of accommodation expense claims (required documentation is described in the table above).

In the event a receipt is lost an employee must first contact the vendor to obtain a duplicate copy of the receipt. If this is not possible, the employee should provide a written explanation of the amount in the "Justification" field in iExpense and acknowledge that a duplicate claim will not be submitted.

8.0 Employee Business Expense Processing

American Express will submit to Enbridge a daily electronic data feed that Enbridge will load into iExpense. This data feed provides all relevant details of each individual American Express cardholder's account activity, excluding American Express card cash advances, undertaken during the current billing cycle.

Enbridge's contract with American Express requires full settlement of approved monthly charges within 60 calendar days in Canada and 45 calendar days in the United States following the date of the *summary* statement, i.e., the **29th** of the month or the closest business day to that date.

American Express cardholders will be notified by e-mail that they have unexpensed transactions in iExpense. All employees must clear their expenses at least once every **30** days. American Express cardholders should review their expense report for accuracy of charges and credits (merchant, date, description, amount, account allocation, etc.). Completion of an expense report must include, but is not limited to:

- Making any necessary adjustments;
- Marking expensed line items as "expensed;"
- Marking all personal charges as "personal;"
- Adding incidental cash expenses;
- Providing a business purpose in the "Justification" field for every expense;
- Noting any required explanatory comments;
- Reconciling American Express card cash advances; and
- Match merchant receipts and/or American Express charge card receipts or other supporting documentation to each line of expense.

Employees should only accept and submit valid charges, ensuring that credits have been received and previously disputed items have been cleared.

Employees **are responsible** for prompt payment to American Express of the following:

- Cash advances on their American Express cards;
- Personal charges that are marked as such on their expense report;
- Delinquency charges incurred on outstanding balances owing on their American Express cards; and
- All unapproved charges.

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All American Express cardholders will also receive a monthly paper statement from American Express. This paper statement will duplicate the electronic data feed loaded into iExpense and will also identify current month American Express card cash advances, if any. The statement can be used to check the accuracy of the electronic data feed. As well, employees should ensure that all prior charges on the statement have been settled and resolve any exceptions.

Employees must, upon completion of an expense report, submit it electronically to their manager for approval. The approver will review the expense report and approve it within **fourteen (14)** calendar days by submitting it electronically through iExpense to Accounts Payable.

In addition to removal of personal charges, each American Express cardholder is responsible for reporting any disputed charges directly to American Express and for managing the dispute (including subsequent credit) through iExpense. Matters that cannot be resolved satisfactorily must be reported to the Company's Manager, Corporate Administration.

After employees have received notification that their expense report has been approved, they must print the Summary Detail Report page of the expense report, which will be automatically bar-coded for record control purposes, attach receipts, sign the report and forward the completed package in the special receipts envelope to their respective Accounts Payable department. Accounts Payable initiates payment to American Express and reimbursement, if any, to employees.

In the event receipts are lost, employees must provide a written explanation in the "Justification" field in iExpense. The reason for this loss should be noted on the expense report being filed.

9.0 Compliance

Unpaid American Express Balances:

- Oracle email notification sent out weekly to employees who have outstanding/unexpensed charges within the last 365 days;
- If an employee's balance is 60 days past due, the employee is provided with an e-mail notification from Corporate Administration;
- If an employee's balance is 72 days past due, the employee's American Express card will be suspended by American Express; the employee and their supervisor are provided with e-mail notification from Corporate Administration and telephone notification from American Express prior to suspension;
- If an employee's balance is 90 days past due, the employee's American Express card will be cancelled and the employee will **not** be given a replacement card; the employee and their supervisor are provided with e-mail notification prior to 75 days (Enbridge must issue Waiver of Liability at this time) and employee and their supervisor will receive an e-mail notification when the card has been cancelled.

The failure to make timely payment of personal charges is a violation of this policy. Accordingly, personal charges and unpaid corporate card balances will be documented on employee files maintained in the appropriate Human Resources Department. As with any other inappropriate employee conduct, these violations should be documented and discussed with employees in regular performance appraisals provided by management.

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 5.9, Attachment, Page 10 of 21

Enbridge is unable to deduct outstanding balances on corporate cards from the remuneration earned by employees. In order to deduct an amount from an employee's remuneration, the employee must provide express written consent.

Enbridge Employees

In addition to those matters included in Sections 7.0 and 8.0 of this Policy, each employee is also responsible for:

- Becoming familiar and complying with all aspects of this Policy;
- Applying for an American Express card;
- Reporting lost or stolen cards and other insurable incidents;
- Obtaining all necessary authorizations prior to incurring business expenses;
- Reconciling American Express card monthly billing and cash advances, if any;
- Preparing and submitting timely, accurate and complete expense reports for review and approval;
- Filing a paper copy of each expense report with appropriate supporting documentation; and
- Returning the American Express card to Enbridge and submitting a final expense report upon cessation of employment.

Employees must promptly pay American Express for all personal American Express card charges, including cash advances, if any, and avoid other card abuses that will **risk** card suspension or cancellation.

Enbridge Business Units and Legal Entities

Enbridge Business Units, and legal entities, within their area of responsibility, are responsible for managing employee business expense activities including:

- Reviewing and approving employee expense reports;
- Reviewing and resolving incidental exceptions to the Policy;
- Ensuring compliance with the Policy; and
- Authorizing employee business travel.

Manager, Corporate Administration

The Manager, Corporate Administration is responsible for the overall administration of this Policy including:

- Managing relationships with American Express Travel and Card, iExpense and Enbridge's preferred suppliers;
- Administering the American Express card program;
- Ensuring distribution of the Policy to employees throughout Enbridge;
- Assisting with interpretations and internal communications in respect of the Policy;
- Monitoring Enbridge's overall compliance with the Policy and reporting to the Vice President, Human Resources and Administration; and

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- Monitoring industry best practices and proposing appropriate amendments to the Policy.

Vice President, Human Resources and Administration

The Vice President, Human Resources and Administration is responsible for:

- Authorizing Enbridge's corporate employee business expense credit card programs;
- Ensuring the development of Enbridge's systems, procedures and business practices to record, control and accurately report all aspects of employee travel, entertainment and related business expenses; and
- Approving or obtaining approval of proposed amendments to the Policy and ensuring communication of such amendments throughout Enbridge.

Audit Services

Audit Services is responsible for conducting employee business expense audits to provide control assurance in respect of effective, efficient and economic operations, management reporting and compliance. In addition, Audit Services may conduct reviews and evaluations in respect of Enbridge's satisfaction of American Express Travel and iExpense support services, merchant acceptance of American Express cards and program security matters.

10.0 Extreme Circumstances

In extreme circumstances related to maintenance of the health and safety of Enbridge employees and the public, or in other emergencies, and when the appropriate Group Vice President or Executive Vice President cannot be notified, employees should exercise prudence and judgment in committing or spending Enbridge resources. Employees must immediately explain such commitment or expenditure and be able to justify and support the business purpose and reasonableness of their nature and amount.

Administrative Edits, K. Burningham - Revised March 27, 2012.

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 5.9, Attachment, Page 12 of 21

ENBRIDGE

Pg. 1

2012/2013 HOTEL PROGRAM

Hotel Name	Address	City	State	Country	RATE CURRECNY AND ROOM TYPE Currency	Room Type 1	SE Start Date 1 Room type 1
Crowne Plaza Hoel North Dallas-addison	14315 Midway Rd	Addison	TX	United States	USD	Deluxe king or 2 beds	1/1/2012
Holiday Inn Austin-town Lake	20 North Ih-35	Austin	TX	United States	USD	1 King nonsmoking - KNGN	1/1/2012
Holiday Inn Battle Creek	12812 Harper Village Dr	Battle Creek	MI	United States	USD	Two Queen Beds	1/1/2012
Hampton Inn & Suites Bemidji	1019 Paul Bunyan Dr South	Bemidji	MN	United States	USD	Standard	1/1/2012
Hyatt Place Minneapolis Arpt South	7800 International Dr	Bloomington	MN	United States	USD	Standard	1/1/2012
Radisson Hotel Bloomington By Mall Of America	1700 East American Blvd	Bloomington	MN	United States	USD	Standard	1/1/2012
Sofitel Bogota Victoria Regia	Carrera 13 No 85 80	Bogota		Colombia	COP	SUPERIOR QUEEN BED	1/1/2012
Sleep Inn Bracebridge	510 Muskoka Rd. 118 West	Bracebridge	ON	Canada	CAD	Standard	1/1/2012
Canad Inns Brandon	1125 18th St	Brandon	MB	Canada	CAD	2 Queen Beds	1/1/2012
Holiday Inn Express Hotel & Suites Brighton	8079 Challis Dr	Brighton	MI	United States	USD	2 queen bed	1/1/2012
Homewood Suites By Hilton Brighton	8060 Challis	Brighton	MI	United States	USD	King studio suite	1/1/2012
Holiday Inn Express Hotel & Suites Brockville	7815 Kent Blvd	Brockville	ON	Canada	USD	1 King or 2 Queen Beds	1/1/2012
Delta Bow Valley	209 - 4th Ave Southeast	Calgary	AB	Canada	CAD	Standard	1/1/2012
International Hotel Suites Calgary	220-4th Ave Southwest	Calgary	AB	Canada	CAD	Studio	1/1/2012
Sheraton Suites Calgary Eau Claire	255 Barclay Parade Southwe	Calgary	AB	Canada	CAD	Standard	1/1/2012
The Westin Calgary	320 - 4th Ave Southwest	Calgary	AB	Canada	CAD	Standard	1/1/2012
Cambridge Hotel And Conference Centre	700 Hespeler Rd	Cambridge	ON	Canada	CAD	Standard	1/1/2012
Holiday Inn Express Chicago Magnificent Mile	640 North Wabash Ave	Chicago	IL	United States	USD	1 Queen,King , DB Bed	1/1/2012
Best Western Plus Parkway Inn & Conference Centre	1515 Vincent Massey Dr	Cornwall	ON	Canada	CAD	Standard	1/1/2012
Hilton Dallas/park Cities	5954 Luther Ln	Dallas	TX	United States	USD	1 King, 2 Queens or 2 Dbl	1/1/2012
Hyatt Summerfield Denver Airport	18741 East 71st St	Denver	CO	United States	USD	Standard	1/1/2012
Magnolia Hotel Denver	818 17th St	Denver	CO	United States	USD	Standard	1/1/2012
Hampton Inn Duluth	310 Canal Park	Duluth	MN	United States	USD	cityview, 1K or 2Q	1/1/2012
Sheraton Duluth Hotel	301 East Superior St	Duluth	MN	United States	USD	Standard	1/1/2012
Crowne Plaza Hotel Edmonton Chateau Lacombe	10111 Bellamy Hill	Edmonton	AB	Canada	CAD	One king or two dbl beds	1/1/2012
Delta Edmonton Centre Suite Hotel	10222-102 St	Edmonton	AB	Canada	CAD	Standard	1/1/2012
Four Points By Sheraton Edmonton South	7230 Argyll Rd	Edmonton	AB	Canada	CAD	Standard	1/1/2012
The Westin Edmonton	10135 100th St	Edmonton	AB	Canada	CAD	Standard	1/1/2012
Marriott Edmonton At River Cree Resort	300 East Lapotac Blvd	Enoch	AB	Canada	CAD	Deluxe	1/1/2012
Comfort Suites Escanaba	3600 Ludington St	Escanaba	MI	United States	USD	one king bed	1/1/2012
Peninsula Bay Inn Of Escanaba	2603 North Lincoln Rd	Escanaba	MI	United States	USD	One queen or king bed	1/1/2012
Days Inn Estevan	1305 9th St	Estevan	SK	Canada	CAD	Standard	1/1/2012
Holiday Inn Express Hotel & Suites Fenton	17800 Silver Pkwy	Fenton	MI	United States	USD	One King Bed	1/1/2012
Holiday Inn Express Hotel & Suites Fort Atkinson	1680 Madison Ave	Fort Atkinson	WI	United States	USD	Two queen size beds	1/1/2012
Chateau Nova Hotel	Fort Mcmurray Airport Mod	Fort Mcmurray	AB	Canada	CDN	2 queen	1/1/2012
Radisson Hotel & Suites Fort Mcmurray	435 Gregoire Dr	Fort Mcmurray	AB	Canada	CAD	Comfort	1/1/2012

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Delta Fredericton	225 Woodstock Rd	Fredericton	NB	Canada	CAD	Standard	1/1/2012
Holiday Inn Express Hotel Gaylord	1201 West Main St	Gaylord	MI	United States	USD	Two Queen Beds	1/1/2012
Super 8 Motel - High Level, Ab	9502-114 Ave	High Level	AB	Canada	CAD	Standard	1/1/2012
Best Western Plus Downtown Inn & Suites	915 West Dallas	Houston	TX	United States	USD	Standard	1/1/2012
Magnolia Hotel Houston	1100 Texas Ave	Houston	TX	United States	USD	Standard	1/1/2012
Holiday Inn Express Hotel & Suites Howell	1397 North Burkhart Rd	Howell	MI	United States	USD	One King or Two Queen Bed	1/1/2012
Hampton Inn & Suites Kansas City-country Club Plaza	4600 Summit	Kansas City	MO	United States	USD	One King or 2 Double Beds	1/1/2012
Ramada Lac La Biche	9305 100th St	Lac La Biche	AB	Canada	CAD	Standard	1/1/2012
Holiday Inn Express Hotel & Suites Limon I-70	803 Highway 24	Limon	CO	United States	USD	King or Two Queen Beds	1/1/2012
Four Points Sheraton Hotel & Suites London	1150 Wellington Rd South	London	ON	Canada	CAD	Standard	1/1/2012
Candlewood Suites Longview	2904 Tuttle Blvd	Longview	TX	United States	USD	K1QN-1 queen bed studio	1/1/2012
Holiday Inn Express Hotel & Suites Longview North	300 Tuttle Cir	Longview	TX	United States	USD	king bed, micro/fridge	1/1/2012
Homewood Suites By Hilton Toronto-markham	50 Bodrington Ct	Markham	ON	Canada	CAD	Studio Suites	1/1/2012
Hampton Inn Marshall	17256 Sam Hill Dr	Marshall	MI	United States	USD	two queen beds	1/1/2012
Holiday Inn Express Hotel Marshall	17252 Sam Hill Dr	Marshall	MI	United States	USD	Two Queen Sized Beds	1/1/2012
Holiday Inn Express Hotel Merrillville	8375 Georgia St	Merrillville	IN	United States	USD	One King Bed with sofa sl	1/1/2012
Fairfield Inn Minot	900 24th Ave Southwest	Minot	ND	United States	USD	QueenQueen/King	1/1/2012
Delta Centre-ville	777 University St	Montreal	QC	Canada	CAD	Standard	1/1/2012
Heritage Hotel	27 Mackenzie Dr	Norman Wells	NT	Canada	CAD	Standard Room	1/1/2012
Courtyard Oklahoma City Downtown	2 West Reno Ave	Oklahoma City	OK	United States	USD	Quality Room/Quality Room	1/1/2012
Hampton Inn By Hilton Ottawa	100 Coventry Rd	Ottawa	ON	Canada	CAD	Double queen	1/1/2012
The Westin Ottawa	11 Colonel By Dr	Ottawa	ON	Canada	CAD	Standard	1/1/2012
Americinn Pampa	1101 N Hobart	Pampa	TX	United States	USD	Two Queen Beds	1/1/2012
Holiday Inn Express Hotel & Suites Pampa	3119 Perryton Pkwy	Pampa	TX	United States	USD	TWO QUEEN DS, DELUXE	1/1/2012
Crest Hotel	222 1st Ave West	Prince Rupert	BC	Canada	CAD	1 queen cityview standard	1/1/2012
Holiday Inn Hotel & Suites Regina	1800 Prince Of Wales Dr	Regina	SK	Canada	CAD	Two queen beds	1/1/2012
Sandman Hotel Regina	1800 Victoria Ave East	Regina	SK	Canada	CAD	Standard	1/1/2012
The Saint Paul Hotel	350 Market St	Saint Paul	MN	United States	USD	Standard	1/1/2012
Grand Hyatt San Antonio	600 East Market St	San Antonio	TX	United States	USD	Standard	1/1/2012
The Westin San Diego	400 West Broadway	San Diego	CA	United States	USD	Standard	1/1/2012
Best Western Plus Guildwood Inn	1400 Venetian Blvd	Sarnia	ON	Canada	CAD	Standard	1/1/2012
Holiday Inn Sarnia	1498 Venetian Blvd	Sarnia	ON	Canada	CAD	2 double beds	1/1/2012
Holiday Inn Express Hotel & Suites Schererville North	1773 Fountain Park Dr	Schererville	IN	United States	USD	King Size Bed	1/1/2012
Sleep Inn And Suites	111 15th St	Shamrock	TX	United States	USD	Standard	1/1/2012
Coast Edmonton East Hotel	2100 Premier Way	Sherwood Park	AB	Canada	CAD	Comfort	1/1/2012
Hampton Inn & Suites Springfield	2750 North Glenstone Ave	Springfield	MO	United States	USD	Standard	1/1/2012
Hampton Inn & Suites Stillwater	717 East Hall Of Fame Ave	Stillwater	OK	United States	USD	King or Double Queen	1/1/2012
Holiday Inn Stillwater U University East	715 South Country Club Rd	Stillwater	OK	United States	USD	Double Queen Room	1/1/2012
Holiday Inn Express Hotel & Suites Superior	303 2nd Ave East	Superior	WI	United States	USD	Two Queen Beds	1/1/2012
Best Western Plus Terrace Inn	4553 Greig Ave	Terrace	BC	Canada	CAD	Standard	1/1/2012
Four Points By Sheraton St. Catharines Niagara	3530 Schmon Pkwy	Thorold	ON	Canada	CAD	Standard	1/1/2012
Valhalla Inn Thunder Bay	1 Valhalla Inn Rd	Thunder Bay	ON	Canada	CAN	Standard Queen	1/1/2012
Delta Toronto East	2035 Kennedy Rd	Toronto	ON	Canada	CAD	Standard	1/1/2012
Fairmont Royal York	100 Front St West	Toronto	ON	Canada	CAD	Standard	1/1/2012
Radisson Hotel Toronto East	55 Hallcrown Pl	Toronto	ON	Canada	CAD	Standard	1/1/2012
Sheraton Gateway Hotel Toronto International	Terminal 3	Toronto	ON	Canada	CAD	Standard	1/1/2012
The Westin Prince Toronto	900 York Mills Rd	Toronto	ON	Canada	CAD	Standard	1/1/2012

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SEASON ONE DATES AND RATES			SEASON 2 DATES AND RATES				SEASON 3 DATES AND RATES				SEASON 4 DATES AND RATES			
End Date 1 Room type 1	Client Rate Single Occupancy	Client Rate Double Occupancy	Start Date 2 Room type 1	End Date 2 Room type 1	Client Rate Single Occupancy	Client Rate Double Occupancy	Start Date 3 Room type 1	End Date 3 Room type 1	Client Rate Single Occupancy	Client Rate Double Occupancy	Start Date 4 Room type 1	End Date 4 Room type 1	Client Rate Single Occupancy	Client Rate Double
12/31/2013	78.00	78.00												
12/30/2012	129.00	129.00	12/31/2012	12/31/2013	135.00	135.00								
12/31/2013	137.00	137.00												
12/31/2013	92.00													
5/31/2012	114.00	114.00	6/1/2012	10/31/2012	124.00	124.00	11/1/2012	12/31/2012	114.00	114.00	1/1/2013	12/31/2013	129.00	129.00
12/31/2013	99.00	99.00												
12/31/2013	575,000.00	575,000.00												
1/31/2012	79.99	79.99	2/1/2012	5/31/2012	99.99	99.99	6/1/2012	9/30/2012	119.99	119.99	10/1/2012	12/31/2013	79.99	79.99
12/31/2013	89.00	89.00												
12/31/2013	78.00	78.00												
12/31/2013	99.00	149.00												
5/31/2012	134.10	134.10	6/1/2012	9/3/2012	143.10	143.10	9/4/2012	12/31/2012	134.10	134.10				
12/31/2012	169.00	169.00	1/1/2013	12/31/2013	174.00	174.00								
12/31/2013	174.00	179.00												
12/31/2012	235.00	235.00	1/1/2013	12/31/2013	240.00	240.00								
12/31/2012	239.00	244.00	1/1/2013	12/31/2013	244.00	254.00								
3/31/2012	95.00	95.00	4/1/2012	9/30/2012	95.00	95.00	10/1/2012	12/31/2012	95.00	95.00	1/1/2013	12/31/2013	95.00	95.00
3/31/2012	119.00	119.00	4/1/2012	6/30/2012	159.00	159.00	7/1/2012	8/31/2012	159.00	159.00	9/1/2012	12/31/2013	159.00	159.00
5/31/2012	109.99	119.99	6/1/2012	8/31/2012	109.99	119.99	9/1/2012	12/31/2012	109.99	119.99				
12/31/2013	169.00	169.00												
12/31/2013	139.00	139.00												
12/31/2013	149.00	192.00												
5/24/2012	89.00	109.00	5/25/2012	9/2/2012	119.00	149.00	9/3/2012	10/20/2012	104.00	124.00	10/21/2012	12/31/2013	79.00	89.00
5/31/2012	99.00	99.00	6/1/2012	10/20/2012	129.00	129.00	10/21/2012	12/31/2012	99.00	99.00	1/1/2013	12/31/2013	99.00	99.00
12/31/2013	113.00	113.00												
12/31/2013	141.00	141.00												
12/31/2012	120.00	120.00	1/1/2013	12/31/2013	120.00	120.00								
12/31/2013	162.00	165.00												
12/31/2012	159.00	159.00												
4/30/2012	90.00	90.00	5/1/2012	10/31/2012	90.00	90.00	11/1/2012	4/30/2013	90.00	90.00	5/1/2013	12/31/2013	90.00	90.00
12/31/2013	73.00	83.00												
12/31/2013	89.00	89.00												
3/31/2012	81.00	81.00	4/1/2012	8/31/2012	81.00	81.00	9/1/2012	12/31/2013	81.00	81.00				
12/31/2013	94.00	94.00												
12/31/2012	155.00	155.00	1/1/2013	12/31/2013	195.00	195.00								
12/31/2013	184.00	184.00												

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Holiday Inn Select Tyler	5701 South Broadway	Tyler	TX	United States	USD	One king bed or two full	1/1/2012
Hyatt Regency Vancouver	655 Burrard St	Vancouver	BC	Canada	CAD	Standard	1/1/2012
Palomar A Kimpton Hotel	2121 P St Northwest	Washington	DC	United States	USD	DELUXE	1/1/2012
Holiday Inn Express Weatherford	850 Interstate I-20 East	Weatherford	TX	United States	USD	KNGN	1/1/2012
La Quinta Inn & Suites Weatherford	1915 Wall St	Weatherford	TX	United States	USD	Standard	1/1/2012
Fairmont Winnipeg	2 Lombard Pl	Winnipeg	MB	Canada	CAD	Standard	1/1/2012
Yellowknife Inn, The	Po Box 490	Yellowknife	NT	Canada	CAD	One or two double beds	1/1/2012

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12/31/2013	138.00	139.00											
3/31/2012	89.00	89.00	4/1/2012	6/12/2012	89.00	89.00	6/13/2012	10/9/2012	89.00	89.00	10/10/2012	12/31/2012	89.00	89.00
9/26/2012	129.00	129.00	9/27/2012	10/3/2012	129.00	129.00	10/4/2012	12/31/2013	129.00	129.00				
12/31/2012	120.00	120.00												
12/31/2013	148.00	159.00												
12/31/2013	69.99	69.99												
12/31/2013	115.00	115.00												
6/19/2012	129.00	129.00	6/20/2012	9/7/2012	139.00	139.00	9/8/2012	12/31/2013	129.00	129.00				
12/31/2012	109.00	109.00	1/1/2013	12/31/2013	119.00	119.00								
12/31/2013	103.00	103.00												
3/31/2012	84.99	89.99	4/1/2012	6/30/2012	79.99	84.99	7/1/2012	9/30/2012	74.99	79.99	10/1/2012	12/31/2013	69.99	74.99
12/31/2013	99.00													
12/31/2013	129.00	129.00												
12/31/2013	94.00	94.00												
12/30/2012	91.00	91.00	12/31/2012	12/31/2013	91.00	91.00								
12/31/2013	109.00	109.00												
12/31/2012	159.99	159.99												
4/30/2012	145.00	145.00	5/1/2012	10/31/2012	165.00	165.00	11/1/2012	5/31/2013	145.00	145.00	6/1/2013	12/31/2013	165.00	165.00
12/31/2012	245.00													
12/31/2012	149.00	149.00												
12/31/2012	135.00	145.00	1/1/2013	12/31/2013	140.00	150.00								
3/31/2012	187.00	189.00	4/1/2012	11/30/2012	209.00	209.00	12/1/2012	3/31/2013	187.00	189.00	4/1/2013	12/31/2013	209.00	215.00
12/31/2013	79.99	79.99												
12/31/2013	99.00	105.00												
5/31/2012	124.00	124.00	6/1/2012	9/30/2012	145.00	145.00	10/1/2012	5/31/2013	124.00	124.00	6/1/2013	12/31/2013	145.00	145.00
12/31/2013	119.99	119.99												
12/31/2013	117.00	130.00												
12/31/2013	172.00	172.00												
12/31/2013	159.00	159.00												
12/31/2013	199.00	219.00												
12/31/2012	99.00	99.00												
12/31/2013	120.00	120.00												
12/31/2012	109.00	109.00	1/1/2013	12/31/2013										
12/31/2013	84.55	84.55												
12/31/2012	114.00	114.00	1/1/2013	12/31/2013	119.00	119.00								
12/31/2013	94.00	98.00												
12/31/2013	85.00	85.00												
8/30/2012	94.00	94.00	8/31/2012	12/31/2012	104.00	104.00	1/1/2013	8/29/2013	99.00	99.00	8/30/2013	12/31/2013	109.00	109.00
5/31/2012	94.00	99.00	6/1/2012	8/31/2012	104.00	119.00	9/1/2012	12/30/2012	94.00	99.00	12/31/2012	12/31/2013	104.00	109.00
3/31/2012	109.99	109.99	4/1/2012	6/30/2012	113.99	113.99	7/1/2012	12/31/2012	115.99	115.99				
12/31/2013	119.00	119.00												
12/31/2013	120.00	125.00			120.00				120.00				120.00	
12/31/2013	129.00	142.00												
3/31/2012	190.00	190.00	4/1/2012	6/30/2012	245.00	245.00	7/1/2012	9/8/2012	190.00	190.00	9/9/2012	12/31/2013	245.00	245.00
12/31/2012	116.99	116.99	1/1/2013	12/31/2013	117.99	117.99								
12/31/2012	179.00	179.00	1/1/2013	12/31/2013	179.00	179.00								
12/31/2013	160.00	161.00												

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12/31/2013	90.00	90.00												
12/31/2013	148.00	155.00												
2/26/2012	229.00	229.00	2/27/2012	6/27/2012	259.00	259.00	6/28/2012	9/3/2012	229.00	229.00	9/4/2012	12/31/2012	259.00	269.00
12/31/2013	90.00	90.00												
12/31/2013	75.00	78.00												
12/31/2012	179.00	179.00	1/1/2013	12/31/2013	184.00	184.00								
12/31/2012	149.00	149.00	1/1/2013	12/31/2013	149.00	149.00								

CANCELLATION POLICY AND AMENITIES				
Breakfast Included	**Internet Included**	**Cancellation Policy**	**LRA**	**Parking Included**
Y	Y	24 Hours	Y	Y
N	Y	6PM	Y	Y
N	Y	6PM	Y	Y
Y	Y	24 Hours	Y	Y
Y	Y	4PM	Y	Y
N	Y	6PM	Y	Y
Y	N	24 Hours	Y	Y
Y	Y	24 Hours	Y	Y
N	Y	24 Hours	Y	Y
Y	N	6PM	Y	N
Y	Y	4PM	Y	Y
Y	Y	6PM	Y	N
N	Y	4PM	Y	N
N	Y	24 Hours	Y	N
N	Y	4PM	Y	N
N	Y	24 Hours	Y	N
N	Y	24 Hours	Y	N
N	Y	6PM	Y	N
N	Y	4PM	Y	Y
Y	Y	24 Hours	Y	N
Y	N	4PM	Y	Y
N	Y	24 Hours	Y	N
Y	Y	6PM	Y	Y
Y	Y	6PM	Y	N
Y	N	6PM	Y	Y
N	Y	6PM	Y	N
N	Y	6PM	Y	N
N	Y	6PM	Y	N
N	Y	6PM	Y	Y
N	Y	4PM	Y	N
N	N	6PM	Y	Y
Y	Y	4PM	Y	Y
Y	N	24 Hours	Y	Y
Y	Y	6PM	Y	N
Y	N	4PM	Y	Y
Y	N	6PM	N	Y
Y	Y	24 Hours	Y	Y
N	Y	24 Hours	Y	Y

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N	Y	4PM	Y	Y
N	Y	24 Hours	Y	N
Y	Y	6PM	Y	N
Y	Y	24 Hours	Y	Y
Y	N	24 Hours	Y	N
Y	Y	6PM	Y	Y
Y	Y	6PM	Y	Y
Y	Y	24 hours	Y	Y
Y	Y	6PM	Y	Y
N	Y	4PM	Y	Y
N	Y	6PM	Y	Y
Y	Y	6PM	Y	Y
Y	Y	6PM	Y	Y
Y	Y	6PM	Y	Y
Y	Y	6PM	Y	Y
Y	N	6PM	Y	Y
Y	N	6PM	Y	Y
N	Y	6PM	Y	N
Y	N		Y	Y
N	Y	6PM	Y	N
Y	Y	6PM	Y	Y
N	Y	4PM	Y	N
Y	Y	4PM	Y	Y
Y	Y	6PM	Y	N
Y	Y	4PM	Y	Y
Y	Y	6PM	Y	N
N	N	24 Hours	Y	Y
N	Y	6PM	Y	Y
N	Y	24 Hours	Y	Y
N	Y	24 Hours	Y	N
N	Y	6PM	Y	N
N	Y	6PM	Y	N
Y	Y	4PM	Y	Y
N	N	6PM	Y	Y
Y	Y	6PM	Y	Y
Y	Y	24 Hours	Y	Y
N	Y	6PM	Y	Y
Y	N	6PM	Y	Y
Y	Y	6PM	Y	Y
N	Y	6PM	Y	Y
Y	Y	24 Hours	Y	Y
N	Y	24 Hours	Y	Y
N	Y	6PM	Y	Y
N	Y	4PM	Y	Y
N	Y	4PM	Y	N
N	Y	6PM	Y	N
N	Y	24 Hours	Y	Y
N	Y	6PM	Y	N
N	Y	6PM	Y	N

Y	Y	6PM	Y	Y
Y	Y	Noon	Y	N
N	N	6PM	Y	N
Y	Y	6PM	Y	Y
Y	Y	6PM	Y	Y
N	N	6PM	Y	N
Y	N	6PM	Y	Y

CCC INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 4

Please provide a detailed budget for "Memberships" for 2011, 2012 and 2013. In addition, please file the actual amounts for 2007-2010 for this cost item.

RESPONSE

Table 1 provides a breakdown of the Memberships line.

Table 1
Enbridge Gas Distribution
Memberships
2013 Budget, 2012 Estimate, 2011 Historical

	$Millions	Budget 2013	Estimate 2012	Actuals 2011
1	Sponsorships and Membership	$2.5	$2.3	$3.3
2	Canadian Gas Association	0.5	0.5	0.5
3	American Gas Association	0.1	0.1	-
4	OEA, Toronto Board of Trade, OEN Sponsorships	0.2	0.2	0.2
5	Municipal Outreach Fundraisers	0.1	0.1	0.1
6	Sunnybrook sponsorship	0.1	0.1	-
7	Total	$3.4	$3.2	$4.0

Witnesses: S. Kancharla
R. Lei

Table 2 provides the historical amounts starting from 2007.

Table 2
Enbridge Gas Distribution
Memberships
2010-2007 Historical

$Millions	Actuals 2010	Actuals 2009	Actuals 2008	Actuals 2007
Memberships	$3.6	$2.6	$2.5	$2.5

Witnesses: S. Kancharla
R. Lei

CCC INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/T3/S1/p. 4

Please provide a detailed budget for "Employee Training and Development" for 2011, 2012 and 2013. In addition, please file the actual amounts for 2007-2010 for this cost item.

RESPONSE

Table 1 provides a detailed description of the employee training and development costs.

Table 1

$Millions	Budget 2013	Estimate 2012	Actual 2011
1. Department employee training and development	$ 2.7	$ 2.6	$ 2.3
2. Higher education awards	0.5	0.5	0.5
3. Relocation costs	0.5	0.5	2.3
4. Executive training and development	0.2	0.2	0.3
5. Employee education refund	0.2	0.2	0.1
6. Total	$ 4.1	$ 4.0	$ 5.6

Table 2 provides the historical amounts starting from 2007.

Table 2

$Millions	Budget 2013	Estimate 2012	Actual 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007
Employee Training and Development	$4.1	$4.0	$5.6	$2.9	$3.0	$2.7	$2.0

Witnesses: S. Kancharla
R. Lei

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit A2, Tab 1, Schedule 1

a) Please update the table in paragraph 61 on page 17 to reflect actual data for 2011.

b) Please provide the inflation rates used to arrive at the 2013 constant dollar figures shown in the table in paragraph 61. Please identify which inflation factor has been used.

RESPONSE

a) Please refer to Exhibit D1, Tab 3, Schedule 1, Corrected: 2012-07-27, Table 6 on page 29 which reflects actual data for 2011.

b) Inflation factors which have been used for constant dollar figures are:

Year	GDP IPI (2002=100)
2002	100.00
2003	101.50
2004	103.25
2005	105.45
2006	107.95
2007	110.35
2008	112.93
2009	114.43
2010	115.90
2011	116.78
2012	118.79
2013	120.84

Witness: R. Lei

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 25, Schedule 1

a) Please update Table 1 to include actual data for 2011.

b) How has the O&M forecast for 2013 been adjusted or impacted by the service quality requirement figures that are below the target levels?

RESPONSE

a) Table 1: SQR Targets Vs. Actuals is updated below with 2011 data

Service Quality Requirement	Target	2009	2010	2011
Appointments Met Within the Designated Time Period	85.0%	96.3%	94.7%	95.3%
Emergency Calls Responded within One Hour	90.0%	96.2%	94.2%	95.2%
Time to Reschedule Missed Appointments	100.0%	97.6%	95.2%	92.8%
Number of Days to Reconnect a Customer	85.0%	94.3%	93.9%	93.8%
Call Answering Service Level	75.0%	74.1%	65.3%	75.2%
Number of Calls Abandon Rate	10.0%	7.0%	11.6%	4.1%
Meter Reading Performance	0.50%	0.47%	0.66%	0.7%
Number of Days to Provide a Written Response	80.0%	89.0%	N/A	N/A

b) Time to Reschedule Missed Appointments is below target. Missed appointments not rescheduled within two hours, as compared to the total number of appointments represents 0.22% of total appointments (97/43618). The Company acknowledges the importance of customer satisfaction and the timely rescheduling of missed appointments; however attainment of a perfect 100% score is virtually impossible. Nonetheless, EGD will continue to place priority on this standard, striving to reach the OEB's target of 100%. In 2012, Operations will be making a capital investment in handheld devices in order to monitor real time activities. It is the Company's expectation that the results will begin to improve later in the year.

Witnesses: T. Ferguson
K. Lakatos-Hayward
M. Torriano
M. Wagle

Meter Reading Performance is below target. Enbridge reads its meters every other month and therefore every other month, meters are estimated. If a meter reader misses one meter read, which can happen for a variety of reasons, that meter will immediately appear as having three consecutive estimates in the following month. Access to the meter is Enbridge's single largest issue in obtaining meter readings. System-wide, Enbridge has approximately 550,000 inside meters, which means that meter reading can be impacted by a customer's extended absence. In winter months, it can be difficult to get meter reads for some premises, given the impact snow accumulation can have on the meter reader's ability to access a meter. The Company has also encountered difficulties gaining access to meters installed in the backyard of a home where a gate is locked, where meters are blocked by equipment at the premise or where properties are vacant. These issues can result in up to 5,000 meters being inaccessible in a given month depending on the time of year, which makes meeting the Meter Reading Performance target very difficult.

Over the past few years, the Company has undertaken several initiatives to assist in meeting the Meter Reading Performance target. These initiatives have included upgrading handheld devices and software, increasing the number of off cycle reads and attempting to contact customers to arrange for an appointment to gain access to the meter. Enbridge expects that these initiatives, and better use of the billing information collected using the new CIS, will assist in reducing the number of consecutive meter reading estimates.

In the new CIS, the Company also encountered a number of challenges with the way the CIS counted consecutive meter reading estimates. There have been several enhancements implemented to improve the system's ability to track and report on estimates. In addition, the Company has also enhanced business processes associated with managing billing exceptions that are generated when a meter reading falls outside preset parameters. Lack of knowledge and experience in using the new CIS resulted in many accounts being re-estimated, when the meter read was actually valid, negatively impacting the count of consecutive estimates. The Company has undertaken a significant education and retraining process to ensure that valid meter reads are used in billing our customers and that the meter reading estimates are counted appropriately.

Witnesses: T. Ferguson
K. Lakatos-Hayward
M. Torriano
M. Wagle

Number of Days to Provide a Written Response results are not available. The Company does not have information about its performance relative to this standard for 2010 and 2011. The reason for this is that the Company's new CIS did not separately track written responses to customer complaints. Enbridge has taking steps to address this issue and as of January 2012, the Company now has reporting in place to allow the Company to track and report on the Number of Days to Provide a Written Response.

Witnesses: T. Ferguson
K. Lakatos-Hayward
M. Torriano
M. Wagle

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 1

Please expand Table 5 to reflect actual FTE's for 2007 through 2011, along with the forecasts for 2012 and 2013 (the variance columns are not required).

RESPONSE

Table 5
Enbridge Gas Distribution
Full Time Equivalents (FTE)
2013 Budget, 2012 Estimate, 2007-2011 Actual, and 2007 Board Approved

Line No.	Salary Bands	Col. 1 Budget 2013	Col. 2 Estimate 2012	Col. 3 Actual 2011	Col. 4 Actual 2010	Col. 5 Actual 2009	Col. 6 Actual 2008	Col. 7 Actual 2007	Col. 8 Board Approved 2007
1.	Management	140	138	134	126	118	112	100	250
2.	Supervisory	1,452	1,393	1,181	1,087	1,058	1,098	1,112	955
3.	Union	695	700	653	661	662	681	728	755
4.	Total FTE before Vacancy	2,287	2,231	1,968	1,874	1,838	1,892	1,940	1,961
5.	Vacancy*	-	-	116	72	46	51	130	-
6.	Total FTE	2,287	2,231	2,084	1,947	1,884	1,943	2,070	1,961

* Vacancies were not included in the actual FTE's but included in the budget and the estimate

The Company does not have the ability to easily report on historical vacancies by employee grouping due to the nature of our tracking system. Once the vacancy has been filled, it is removed from the tracking system. In order to provide this level of

Witnesses: S. Kancharla
R. Lei
S. Trozzi

detail, it would require extensive manual effort and the accuracy could not be guaranteed, therefore the value of the information would be dubious.

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 1, Updated

a) Please provide the most recent year-to-date OM&A costs incurred in 2012 in the same level of detail as that shown in Table 3. Please also provide the actual year-to-date expenses incurred in 2011 for the same period.

b) Please provide the most recent year-to-date OM&A costs incurred in 2012 in the same level of detail as that shown in Table 4. Please also provide the actual year-to-date expenses incurred in 2011 for the same period.

RESPONSE

a) Please see table provided on the following page.

Witnesses: S. Kancharla
R. Lei

Table 3
Enbridge Gas Distribution
Other Operating and Maintenance Expense by Category
2012 YTD May Actual vs. 2011 YTD May Actual

Line No.	Particulars ($ millions)	YTD 2012 (a)	YTD 2011 (b)	Difference (c)	% (d)
1.	Salaries and Wages	$58.7	$55.3	$3.4	6.2%
2.	Benefits	15.0	12.2	2.8	23.1%
3.	Short Term Incentive Program	8.8	6.8	2.0	29.8%
4.	Employee Training and Development	1.0	1.5	(0.5)	-31.6%
5.	Materials and Supplies	2.8	1.7	1.1	66.6%
6.	Outside Services	20.2	16.1	4.1	25.6%
7.	Regulatory Costs	2.6	2.5	0.1	2.5%
8.	Consulting	3.3	2.0	1.4	68.4%
9.	Repairs and Maintenance	0.9	0.7	0.2	36.4%
10.	Fleet	4.0	3.6	0.4	11.3%
11.	Rents and Leases	2.5	1.8	0.8	44.0%
12.	Telecommunications	1.3	0.8	0.5	56.9%
13.	Travel and Other Business Expenses	1.3	1.3	0.0	1.9%
14.	Memberships	1.4	1.9	(0.5)	-24.0%
15.	Claims, Damages and Legal Fees	0.3	0.3	(0.0)	-0.1%
16.	Interest on Security Deposits	0.4	0.4	(0.0)	-8.2%
17.	Provision for Uncollectibles	6.2	4.1	2.1	51.4%
18.	Internal Allocations and Recoveries	(3.0)	(3.1)	0.1	-2.0%
19.	Other	1.0	1.4	(0.5)	-33.3%
20.	Subtotal	128.7	111.2	17.6	15.8%
21.	Capitalization (A&G)	(13.5)	(9.4)	(4.1)	43.3%
22.	Capitalization	(22.8)	(21.5)	(1.3)	5.9%
23.	Non-Utility Allocations	(0.9)	(1.0)	0.1	-10.4%
24.	Subtotal Other Utility O&M Expense	91.5	79.2	12.3	15.6%
25.	Conservation Services	2.5	2.3	0.1	5.8%
26.	Total Other Utility O&M Expense before Eliminations	94.0	81.5	12.5	15.3%
27.	Regulatory Eliminations				
28.	To eliminate Conservation Services	(2.5)	(2.6)	0.1	-4.1%
29.	Incremental O&M Allocated to Unregulated Storage	0.0	(0.1)	0.1	-100.0%
30.	Total Eliminations	(2.5)	(2.7)	0.2	-7.6%
31.	Total Other Utility O&M Expense	$91.5	$78.9	$12.7	16.1%

Witnesses: S. Kancharla
R. Lei

b)

Table 4
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2012 YTD May Actual vs 2011 YTD May Actual

Line No.	Categories ($ Millions)	Col. 1 YTD 2012	Col. 2 YTD 2011	Col. 3 Difference	Col. 4 %
1.	Customer Care Service Charges	$34.5	$32.6	$2.0	6.1%
2.	Regulatory Cost Allocation Methodology(RCAM)	13.2	11.1	2.0	18%
3.	Demand Side Management (DSM)	8.6	7.4	1.2	16%
4.	Pension Expense	8.1	1.7	6.5	392%
5.	Other O&M	91.5	78.9	12.7	16%
6.	Total Net Utility O&M Expense	$156.0	$131.6	$24.3	18%

Witnesses: S. Kancharla
R. Lei

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: Exhibit D1, Tab 3, Schedule 1 &
Exhibit D1, Tab 3, Schedule 3, Corrected

a) Please reconcile the annual salary and wage increases of 3.3% for non-union and 3.5% for unions noted on pages 15 and 19 of Exhibit D1, Tab 3, Schedule 1 with the statement at paragraph 9 of Exhibit D1, Tab 3, Schedule 2, Corrected that shows collective agreement increases in 2013 total 3.0%.

b) What is the impact on the test year revenue requirement if the union increases are limited to 2.0% in both 2012 and 2013? Please include the impact on benefits, incentive compensation and any other costs related to the level of salaries and wages.

c) What is the impact on the test year revenue requirement if the non-union increases are limited to 2.0% in both 2012 and 2013? Please include the impact on benefits, incentive compensation and any other costs related to the level of salaries and wages.

RESPONSE

a) The salary increase for unionized employees that is incorporated into the 2013 Budget is 3.0%, as outlined at Exhibit A2, Tab 2, Schedule 1, page 10. Also, please refer to the corrected Exhibit D1, Tab 3, Schedule 1, filed July 27, 2012.

b) If union salary increases were held at 2% in 2012 and again in 2013, the impact on the 2013 revenue requirement and corresponding deficiency would be a reduction of approximately $0.3 million. While the company has run the requested scenario, it should be noted that a contract exists for unionized employees that provides for a salary increase of 3.5% for 2012 and 3.0% for 2013. The forecast impact on salaries and wages, incentive compensation and benefits is broken down below.

Witnesses: S. Kancharla
R. Lei
S. Trozzi
K. Culbert

Union merit increases of 2.0% in both 2012 and 2013

Incremental change increase(decrease)	2012	2013
O&M	($000's)	($000's)
Salaries and wages	(375)	(283)
STIP	(19)	(20)
Benefits	(20)	(20)
Total O&M Change	(414)	(323)
Capital		
Salaries and wages	(218)	(166)
STIP	(5)	(5)
Benefits	(5)	(5)
Total Capital Change	(228)	(177)
Total	(642)	(499)

c) If non-union salary increases were held at 2% in 2012 and again in 2013, the impact on the 2013 revenue requirement and corresponding deficiency would be a reduction of approximately $1.5 million. The forecast impact on salaries and wages, incentive compensation and benefits is broken down below.

Non-Union merit increases of 2.0% in both 2012 and 2013

Incremental change increase(decrease)	2012	2013
O&M	($000's)	($000's)
Salaries and wages	(914)	(1,106)
STIP	(173)	(181)
Benefits	(79)	(80)
Total O&M Change	(1,166)	(1,366)
Capital		
Salaries and wages	(530)	(649)
STIP	(47)	(49)
Benefits	(21)	(21)
Total Capital Change	(598)	(719)
Total	(1,764)	(2,085)

Witnesses: S. Kancharla
R. Lei
S. Trozzi
K. Culbert

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 2

Please confirm the following under the originally filed figures:

a. Other O&M increased at an average rate of 2.5% per year from 2007 to 2011.

b. Under the current forecast and budget, Other O&M is proposed to increase by 16.3% from 2011 to 2013.

c. If Other O&M continued at the same rate in 2012 and 2013 as the average from 2007 to 2011, the 2013 Other O&M would be $225.9 million, and the deficiency would be reduced by $24.1 million.

RESPONSE

a. The average other O & M rate of increase per year from 2007 to 2011 is approximately 2.5%, as seen in the original evidence.

b. The increase of 16.3% from 2011 to 2013 is correct.

c. These figures are correct based on 2.5%.

Witnesses: S. Kancharla
R. Lei

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 24

Please confirm the following under the updated figures:

a. Other O&M increased at an average rate of 3.75% per year from 2007 to 2011.

b. Under the current forecast and budget, Other O&M is proposed to increase by 10.3% from 2011 to 2013.

c. If Other O&M continued at the same rate in 2012 and 2013 as the average from 2007 to 2011, the 2013 Other O&M would be $241.9 million, and the deficiency would be reduced by $5.9 million.

RESPONSE

a. The average other O & M rate of increase rate per year from 2007 to 2011 is approximately 3.75%, as seen in the updated evidence.

b. The increase of 10.3% from 2011 to 2013 is correct.

c. These figures are correct based on 3.75%.

Witnesses: S. Kancharla
R. Lei

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 26

Please provide details of the higher provision for uncollectibles and the higher STIP included in the $9.7 million (4.5%) increase in 2011 Other O&M from the prefiled evidence to the Update. With respect to the uncollectibles, please provide the audit memo or other internal document justifying the increase and the reasons for it.

RESPONSE

Details of Increase

Line No.	Particulars ($ millions)	Actual 2011	Historical 2011	Difference
1.	Short Term Incentive Program	$25.2	$22.3	$2.9
2.	Provision for Uncollectibles	21.5	16.8	4.7
		$46.7	$39.1	$7.6

Higher STIP

The increase reflects higher levels of Company performance in the respective years.

Higher Provision for uncollectibles

The evidence was prepared based on best information and analysis available at the time, including the Company's then current understanding of the impact of deficiencies in arrears reporting which, unfortunately, had understated arrears balances. This deficiency came to light in Q4 2011 and the actual provision for uncollectibles of $21.5 million was the result of more information and analysis that became available.

Witnesses: S. Kancharla
R. Lei
S. McGill
S. Trozzi

The attached interrogatory response from EB-2012-0055 includes a document titled Allowance for Doubtful Accounts, dated December 9, 2011, which informed management's decision with respect to the amounts to be booked for the provision for uncollectibles in 2011. This document was reviewed with external auditors.

Witnesses: S. Kancharla
R. Lei
S. McGill
S. Trozzi

Filed: 2012-07-24
EB-2012-0055
Exhibit I
Tab 2
Schedule 4
Page 1 of 3
Plus Attachment

CME INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 2, Page 2 of 3

EGD states that the Provision for Uncollectibles increased by $10 million mainly due to adjustments required to correct deficiencies in accounts receivable reporting that were recognized in 2011. CME wishes to better understand the deficiencies which resulted in the $10 million increase. To this end:

(a) Please describe the deficiencies recognized in 2011;

(b) Please describe the impact which these recently identified deficiencies have had, if any, in the years 2007, 2008, 2009 and 2010; and

(c) Please explain why these deficiencies were not identified prior to 2011.

RESPONSE

a) There are two categories of the deficiencies in accounts receivable reporting.
   i. First, is the impact of adjustments in 2010 and 2011 related to the true-up of the General Ledger and Accounts Receivable subledger stemming from the Company's new CIS implementation.

   ii. Second, mass market arrears balances, which are used in the determination of uncollectible accounts, had been understated. This understatement related to sales for 2009 and 2010; and up to the time it was corrected in 2011. The Company recognizes bad debt in the month of sale. However, the Company follows a 27 month write-off cycle i.e. approximate time from sale to write-off is 27 months. Therefore, at any point in time, the Company's Allowance for Doubtful Accounts (ADA) covers expected write-offs for approximately the previous 27 months of sales. Where it is determined that some of those previous months are over or under provided, then adjustments are made in subsequent months. The arrears balances were understated for sales related to the latter part of 2009 to 2011.

Witnesses: R. Lei
A. Patel
S. McGill

b) It is not possible to determine the actual impact these deficiencies had on 2007 to 2010. The Company does not have the required detailed reports or information as at year end for each of 2007 to 2010 to determine what the impact would have been on 2007 to 2010. However, the Company can estimate impacts based on the assumption that the same information available at end of 2011 was available at the end of 2010. Please refer to Table 1 for estimated impacts. The deficiencies caused 2010 earnings to be overstated by $7.7 million. This added to the ESM amount for that year. For 2011, earnings reflect the adjustments required to re-establish the appropriate provision.

Table 1

	2010	2011
Booked	11.5	21.5
Adjust for:		
True-up of GL and AR subledger	2.9	(2.9)
	14.4	18.6
2009/10 Arrears understated	4.8	(4.8)
Would Have Booked	19.2	13.8
Net Earnings Over Stated (Reduced)	7.7	(7.7)

c)

i. Regarding the entry for the true-up between the General Ledger and Accounts Receivable subledger, prior to the new CIS implementation the Company did not have details of the AR subledger and there was no means by which this issue could be identified. A detailed analysis and reconciliation was necessary which occurred over the 2010-2011 period.

ii. Regarding the understated arrears balances, the decline in arrears balances was consistent with business drivers such as improving economic conditions; and enhanced collections efforts. This combined with the fact that the Company's write-off amounts for historical sales were consistent with projections, indicated that the Company's projections were correct. When a

Witnesses: R. Lei
A. Patel
S. McGill

material difference occurred between projected and actual write-off amounts, the Company investigated and identified the reporting issue. SOX controls as documented were complied with and would not have detected the issue earlier. Please refer to the attached document titled Allowance for Doubtful Accounts 2011, date December 9, 2011.

Witnesses: R. Lei
A. Patel
S. McGill

Allowance for Doubtful Accounts 2011

December 9, 2011

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 4 of 22
Filed: 2012-07-24
EB-2012-0055
Exhibit I
Tab 2
Schedule 4
Attachment

Agenda

- Background
- Adjustment to ADA
- Analysis
- Remedy
- Action Plan

ENBRIDGE

Background

- Given the magnitude of the decline in the Mass Market (MM) Allowance for Doubtful Accounts (ADA) during Q3 2011, EGD Management carried out validation procedures to confirm that the drivers of the change were consistent with Management's understanding.

Effective Write-off Rate in Bad Debt Model (i.e forecasted rate for 27 months)

MM Write-off as a % of Sales

Go-Live Q3 09	Q4 09	Q1 10	Q2 10	Q3 10	Q4 10	Q1 11	Q2 11	Q3 11
0.57%	0.57%	0.59%	0.63%	0.59%	0.56%	0.54%	0.57%	0.44%*

*corrected

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 6 of 22
Filed: 2012-07-24
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Exhibit I
Tab 2
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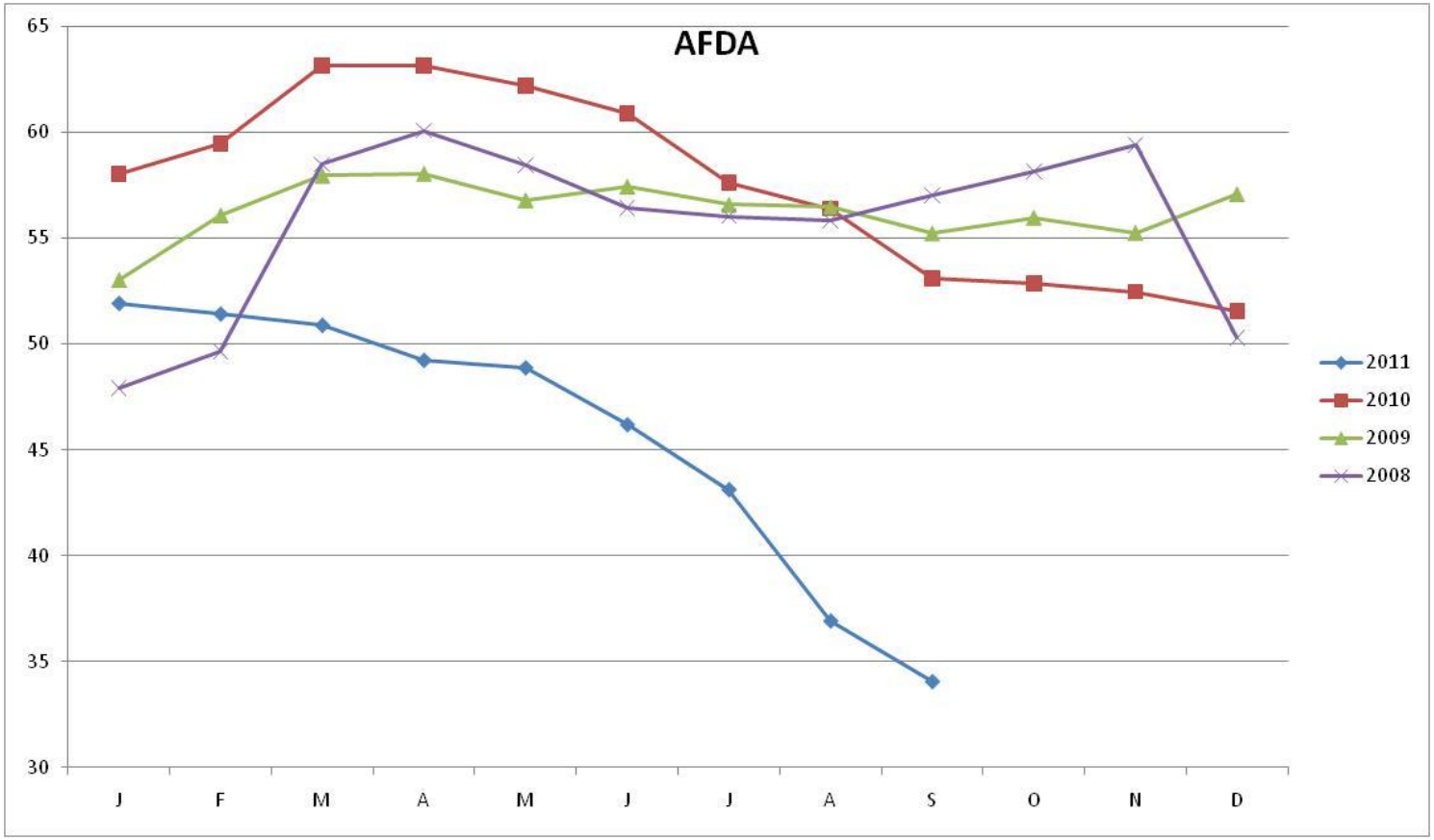
Attachment

Background: ADA Balance



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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 7 of 22
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Adjustment to ADA

- Based on this analysis, EGD has determined that a one-time adjustment is needed to the ADA in Q4 2011.
  - An increase in the ADA is required of $7million-$9 million

- After making this adjustment, the effective write-off rate in the bad debt model would be 0.56%. This would be consistent with historical experience.

Historical and Forecasted Write-off Rates

MM Write-off as a % of Sales

2003	2004	2005	2006	2007	2008
0.50%	0.48%	0.47%	0.51%	0.51%	0.58%

Model Sep09-Nov11
0.56%

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 8 of 22
Filed: 2012-07-24
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Exhibit I
Tab 2
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Analysis

- The MM ADA is predominantly based on delinquent balances which are available from the R22 Delinquent report from SAP (R22).
- The R22 shows the dollar values of all accounts that have been finalized in SAP and the forecasted month of “Delinquency” (3-4 months after move-out date or Final Bill) if uncollected.
- SAP dunning process writes off uncollected accounts 24 months after Final Bill.
- Therefore the finalized balances on the R22, adjusted for some collection over time, are a good predictor of write-offs.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 9 of 22
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Analysis

- Historically, the R22 proved to be reliable in that projected writeoffs were inline with actual writeoffs, allowing for expected variances.
- Beginning October, the R22 became available at account-level detail. Prior to this (including Legacy CIS), the Delinquent report only showed a total amount for each calendar month of delinquency.
- Analysis using the newly available details showed that finalized accounts with credit balances were a substantially higher amount than expectations based on historical experience.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 10 of 22
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Analysis

- The impact of these large credits was to offset and thereby lower the net delinquent balances i.e. finalized debit balances were offset by finalized credit balances.
- Lower delinquent balances resulted in booking less bad debt expense and an ADA that was inadequate to cover EGD's risk around doubtful accounts.
- In the same manner, the large credit balances also offset receivables in AR and understated AR.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 11 of 22
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Analysis: Root Cause of Large Finalized Credits

- Credit balances are created on accounts in the normal course of business:
  - overpayment; refund of security deposit; account adjustments; some credits were existing in Legacy and converted to SAP
- Intended Automatic Transfer functionality in SAP was to transfer balances (credit or debit) from the move-out account to the move-in account. This functionality is not working.
- The auto-issue of in-franchise refund cheques is not occurring.
- This led to a buildup of large finalized credit balances since SAP go-live.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 12 of 22
Filed: 2012-07-24
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Analysis: Validation of R22

- Analysis indicates that the R22 is showing all finalized balances and assigning the appropriate delinquency period, allowing for expected/explainable variances.
- These expected variances cause a variation in predicted versus actual write-off month, but they should be immaterial on an ongoing basis. EGD is working to minimize such variances.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 13 of 22
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Analysis: Validation of Bad Debt process

- The bad debt process is reliable in determining bad debt expense and validating the adequacy of the ADA.
- Given that the SAP dunning process writes off uncollected accounts 24 months after Final Bill, the R22 finalized balances are the most logical input to predicting write-offs.
- As operational process changes are implemented i.e. Auto transfer functionality and/or refund cheque issuance, the amount of credits in the R22 should decline substantially.
- The bad debt process includes comparing actual write-offs to forecasted write-offs based on the R22 finalized balances.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 14 of 22
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Analysis: Validation of Bad Debt process…

- To check specifically for the buildup of credits, EGD will continue to separate out R22 debits and credits each month. Some credits will be part of the normal process but large buildups can be monitored (subject to which operational processes are implemented).

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 15 of 22
Filed: 2012-07-24
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Analysis: Validation of Existing SOX Controls

- ADA SOX controls as documented have been complied with.
- As operational process changes are implemented i.e. Auto transfer functionality and/or refund cheque issue, the amount of credits in the R22 will lessen and credit balances will be for expected reasons.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 16 of 22
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Tab 2
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Attachment

Data Analysis: Sep2011 Data

	#Accounts	Dr $M	#Accounts	Cr $M	Total $M
R22 Net					
MM	128,165	$ 58.8	127,513	(21.9)	36.9
Commercial					
MM	15,988	$ 19.2	16,913	(8.1)	11.2
Collective Accounts					
MM	159	$ 0.0	2	(0.0)	0.0
Owner Occupant					
	8,699	$ 1.3	255	(0.4)	0.9
R22 - Less Comm and Collective and Owner/Occ					
MM	103,319	$ 38.2	108,073	(13.4)	24.8

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 17 of 22
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Remedy

- Until the issue is resolved operationally, for bad debt purposes, EGD will use the R22 debit balances only, adjusting for some mitigation based on data analysis.

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 18 of 22
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Attachment

Remedy: R22 Debits only

R22 - Debits only

Nov 2011 Cycle 21

Month & Year of Delinquency ie. 3-4 months after Final Bill

Sum of Amount	Column Labels								
Row Labels		2007	2008	2009	2010	2011	2012	(blank)	Grand Total
MM									
1			$ 918	$ 1,048	$ 195,162	$ 1,673,568	$2,137,714		$ 4,008,409
2			$ 4,132	$ 2,766	$ 327,663	$ 1,615,517	$2,726,278		$ 4,676,356
3			$ 225	$ 1,240	$ 1,072,520	$ 1,793,118	$3,138,241		$ 6,005,344
4		$ 964	$ 185	$ 1,663	$ 1,112,922	$ 1,562,419			$ 2,678,153
5			$ 1,071	$ 1,313	$ 1,262,022	$ 1,456,754			$ 2,721,160
6				$ 75,349	$ 1,585,008	$ 2,042,817			$ 3,703,174
7			$ 391	$ 23,320	$ 1,684,716	$ 2,292,344			$ 4,000,771
8			$ 2,852	$ 18,832	$ 2,227,038	$ 3,440,340			$ 5,689,063
9			$ 1,408	$ 65,351	$ 2,083,812	$ 4,187,936			$ 6,338,507
10			$ 2,646	$ 82,138	$ 2,367,085	$ 3,347,712			$ 5,799,582
11		$1,565	$ 388	$182,540	$ 1,796,054	$ 2,809,257			$ 4,789,803
12		$ 47	$ 9,454	$131,662	$ 1,685,116	$ 2,665,293			$ 4,491,571
(blank)								$1,164,427	$ 1,164,427
MM Total		$2,576	$23,669	$587,222	$17,399,119	$ 28,887,074	$8,002,233	$1,164,427	$56,066,319

Delinquent debits input to bad debt model months 7-27, subject to some collection over time

Total $ 43 million

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 19 of 22
Filed: 2012-07-24
EB-2012-0055
Exhibit I
Tab 2
Schedule 4
Attachment

Remedy: R22 Credits only

R22 - Credits only

Nov 2011 Cycle 21

Month & Year of Delinquency ie. 3-4 months after Final Bill

Sum of Amount	Column Labels								
Row Labels	2006	2007	2008	2009	2010	2011	2012	(blank)	Grand Total
MM									
1			$ (22,814)	$ (16,248)	$ (399,746)	$ (633,493)	$ (1,014,931)		$ (2,087,233)
2	$ (48)		$ (5,211)	$ (44,872)	$ (516,847)	$ (714,112)	$ (1,675,661)		$ (2,956,750)
3	$ (2,404)		$ (30,193)	$ (29,127)	$ (538,328)	$ (660,217)	$ (360,054)		$ (1,620,324)
4			$ (26,711)	$ (23,231)	$ (330,633)	$ (455,200)			$ (835,775)
5			$ (12,114)	$ (26,850)	$ (410,269)	$ (463,999)			$ (913,231)
6			$ (27,719)	$ (30,775)	$ (430,625)	$ (523,498)			$ (1,012,617)
7		$ (0)	$ (41,593)	$ (29,483)	$ (523,037)	$ (556,574)			$ (1,150,687)
8			$ (31,731)	$ (83,210)	$ (523,896)	$ (709,517)			$ (1,348,354)
9		$ (38)	$ (43,990)	$ (298,597)	$ (740,186)	$ (732,910)			$ (1,815,721)
10			$ (42,503)	$ (273,991)	$ (960,834)	$ (738,591)			$ (2,015,919)
11		$ (20,671)	$ (27,581)	$ (610,139)	$ (720,266)	$ (915,763)			$ (2,294,420)
12		$ (5,731)	$ (71,240)	$ (926,083)	$ (642,786)	$ (957,515)			$ (2,603,355)
(blank)								$ (1,361,021)	$ (1,361,021)
MM Total	$ (2,452)	$ (26,440)	$ (383,400)	$ (2,392,606)	$ (6,737,453)	$ (8,061,389)	$ (3,050,646)	$ (1,361,021)	$ (22,015,407)

Gross credits no longer input to bad debt model months 3-27

Total $ (17) million

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 20 of 22
Filed: 2012-07-24
EB-2012-0055
Exhibit I
Tab 2
Schedule 4
Attachment

Remedy: ADA/Bad Debt Impact

Forecasted Adjustment to ADA $million

	Credits & Mitigation:	Bad Debt Incr (Decr)
1	Impact of removing credits from delinquent balances (Nov 2011 R22)	14
2	Historical/undated debits not written off	2
3	Mitigating Items: final Cr match to final Dr; final Dr match to Active acct; Owner/Occupant final Cr; unpostables; final credits unable to refund	(8)
4	**Net Impact**	**8**

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 21 of 22
Filed: 2012-07-24
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Exhibit I
Tab 2
Schedule 4
Attachment

Action Plan

Action Plan

	Completion Date
Validate R22	Complete
Validate Bad Debt Process	Complete
Validate Existing ADA SOX controls	Complete
Handle ongoing Cr & Dr balances until operational processes implemented	on going
Review need for additional ADA SOX controls	Q2 2012
Minimize expected/explainable R22 writeoff variances	Q3 2012
Implement other reasonableness checks	Q4 2011
Clear backlog of Cr & Dr (incl validation of operational SOX controls)	TBD

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Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D1, Schedule 14.3, Attachment, Page 22 of 22
Filed: 2012-07-24
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Exhibit I
Tab 2
Schedule 4
Attachment

SEC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 4

Please provide a table, using the updated data, in the form of Table 2, but replacing columns (c) and (d) with five new columns, one each for actuals for each year 2007 through 2011.

RESPONSE

Please see the response to CCC Interrogatory #5 at Exhibit D1, Schedule 5.5.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

SEC INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 7 and 12

Please provide all memos, emails, and other communications dealing in whole or in part with the relationship, if any, between a) actual 2011 and/or forecast 2012 O&M amounts, and b) budget 2013 O&M amounts to be included in the rate application.

RESPONSE

Given the size of the Enbridge Gas Distribution organization, it is not practical to undertake a search and review of all emails and other communications addressing broad topics such as annual budgets. Instead, the Company has directed its review in response to this question to the materials provided to the Executive Management Team ("EMT") in their review of the 2013 budget.

Attached are the presentations made to the EMT in September 2011 as a result of which the 2013 Regulatory budget was approved. These presentations set out comparisons between 2012 and 2013 costs. Certain items that do not relate to the regulated utility have been redacted.

Witnesses: S. Kancharla
R. Lei

Gas Distribution

2012 Budget
EMT Review #3

September 6th , 2011

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Agenda

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- 2012 Budget input change
- 2012 Budget earnings update
- 5% O&M reduction by department
- 2013 Budget input change
- 2013 earnings update
- Next steps

2

Input Change from August 22nd Review

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2012 EGD Budget - Base Case

Budget Input		Sep 6th Review	Aug 22nd Review	Better(Worse) from Aug 22nd	% Change	After-tax Impact
Allowed ROE	%	8.16%	8.44%	-0.28%	-3.3%	($4.1)
Inflation factor	%	1.72%	1.70%	0.02%	1.2%	0.0
O&M	$m	$434	$449	$16	3.5%	11.6
Capital	$m	411	443	33	7.4%	0.1
SSM Revenue	$m	5.8	3.8	2.0	53.3%	1.5
Natural Gas Price	$/10^{3}m^3	$200	$207	($7)	-3.5%	($0.4)

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2012 Principal Budget Inputs

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IR Formula

Key Budget Inputs	2012 Budget	2012 LRP	2011 Fcst	Variance from 2012 LRP	Variance from 2011 Fcst	% Variance from 2012 LRP	% Variance from 2011 Fcst	After tax change from LRP ($m)
Customer Adds	37,927	37,927	37,046	0	881	0.0%	2.4%	-
Unlock Customers	1,984,734	2,001,468	1,957,716	(16,734)	27,018	-0.8%	1.4%	(5.2)
Inflation Index (GDP IPI FDD)	1.72%	1.70%	0.72%	0.02%	1.00%	1.2%	138.1%	-
Allowed ROE for ESM (1)	**8.16%**	**8.66%**	7.94%	-0.50%	0.22%	-5.8%	2.8%	**(7.3)**
Natural Gas Price (US$/MMBTU) (2)	$4.52	$4.78	$4.27	($0.26)	$0.25	-5.4%	5.9%	(0.5)
								($13.0)

(1) Every 10 basis point change in allowed ROE translates into $1.4m change in earnings

(2) Nymex Henry Hub

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2012 EGD Earnings vs. LRP

$ millions	2012 Budget	2012 LRP	Variance
EGD LOB			
EGD Earnings - Base Case	$132	$126	$6
Stretch - after Tax	-	11	(11)
EGD Earnings after Tax	**132**	**137**	**(5)**
GD Stretch LOB			
GD Stretch after-tax	-	11	(11)
Earnings including GD stretch	**$132**	**$148**	**($16)**
Required Stretch after tax			16
Required Stretch before tax			$39

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2012 EGD Earnings Scenarios

$ million	Sep 6th Review	Aug 22nd Review	Variance from Aug 22nd	S1 - Exclude GD Stretch Target	S2 - Breakeven at 300 bps
Base case*					
EGD earnings after sharing	$132	$121	$11	$132	$149
EGD earnings target	148	148	0	137	148
Earnings gap	(16)	(27)	11	(5)	1
To meet the earnings target					
Required stretch pre-tax	39	48	9	10	43
Earnings sharing after tax	$13	$8	($5)	$3	$15
Utility ROE above the allowed (bps)	2.82%	2.15%	0.67%	1.35%	3.00%

** Base case doesn't reflect any unidentified stretch. The ESM threshold is $135m*

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5% O&M Reduction by Department

$000's	2012 Original Budget	5% reduction Required	Commitment Confirmed	Outstanding Commitment	Revise O&M after -5%	2011 7&5 Fcst	Incr(Decr) 7&5 Fcst	Δ%
Departmental								
Finance	7,671	(745)	(745)	-	6,926	6,322	604	10%
Customer Support (includes bad debts)	99,095	(2,721)	(900)	(1,821)	96,374	92,485	3,889	4%
Energy Supply, Storage Development & Regulatory	13,762	(688)	(400)	(288)	13,074	12,957	117	1%
Legal and Corporate Services	5,462	(273)	-	(273)	5,189	4,856	333	7%
Operations	66,598	(3,330)	-	(3,330)	63,268	60,214	3,054	5%
Information Services	32,612	(1,631)	(500)	(1,131)	30,981	30,960	22	0%
Business Development & Customer Strategy (excluding DSM)	11,252	(563)	(563)	-	10,689	9,465	1,224	13%
Human Resources	47,785	(2,600)	(2,600)	-	45,185	41,827	3,358	8%
Risk Management	1,160	(58)	(58)	-	1,102	1,656	(554)	-33%
Engineering	33,996	(1,700)	(1,700)	-	32,296	29,347	2,949	10%
Public and Government Affairs	9,663	(665)	(665)	-	8,998	8,235	763	9%
Corporate (not subject to 5% reduction)	24,048	(350)	(350)	-	23,698	23,919	(221)	-1%
Sub Total	**353,103**	**(15,324)**	**(8,481)**	**(6,843)**	**337,780**	**322,243**	**15,537**	**5%**
Non-Departmental and Pass-throughs	**96,106**	**(341)**	**(341)**	**-**	**95,765**	**73,187**	**22,578**	31%
EGD Total O&M	**449,210**	**(15,665)**	**(8,822)**	**(6,843)**	**433,545**	**395,430**	**38,115**	10%

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2013 Principal Budget Inputs

Cost of Service

Key Budget Inputs	2013 Budget	2013 LRP	2012 Budget	Variance from 2013 LRP	Variance from 2012 Budget	% Variance from 2013 LRP	% Variance from 2012 Budget	After tax change from LRP ($m)
Customer Adds	38,896	38,896	37,927	0	969	0.0%	2.6%	-
Capital Expenditures ($m)	$422	$411	$443	$11	-$22	2.6%	-4.9%	(1.8)
Ratebase	$4,209	$4,298	$4,041	-$89	$167	-2.1%	4.1%	-
Allowed ROE (FRM) (1)	9.66%	10.04%	8.16%	-0.38%	1.50%	-3.8%	18.4%	(6.4)
Deemed Equity	**40.0%**	**36.0%**	36.00%	4.00%	4.00%	11.1%	11.1%	**16.9**
Natural Gas Price (US$/MMBTU) (2)	$4.56	$5.24	$4.52	($0.68)	$0.04	-13.0%	0.9%	(1.4)
								$7.3

(1) Every 10 basis point change in allowed ROE translates into $1.5m change in earnings

(2) Nymex Henry Hub

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2013 EGD Earnings Profile

$ millions	Equity at 40% Budget	Adjust LRP	Variance	Equity at 36% Budget	LRP	Variance
EGD LOB						
EGD Earnings - Base Case	$144	$150	($6)	$127	$133	($6)
Stretch - after Tax	-	17	(17)	-	17	(17)
EGD Earnings after Tax	144	167	(23)	127	150	(22)
GD Stretch LOB						
GD Stretch after-tax	-	4	(4)	-	4	(4)
Earnings including GD stretch	$144	$171	($27)	$127	$153	($26)
Required Stretch after tax			27			26
Required Stretch before tax			$36			$35

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GD Earnings by Major Business

$ millions	2012 Budget	2012 LRP	2011 7&5Fcst	Variance from 2012 LRP	Variance from 2011 7&5Fcst
EGD [1]	$132	$138	$142	($5)	($10)
Other Utilities					
Unregulated					
Total GD Earnings	$159	$184	$184	($25)	($25)

[1] Earnings budget after PPD without any stretch

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GD Capital Budget by Major Business

$ millions	2012 Budget	2012 LRP	2011 Fcst	Variance from 2012 LRP	Variance from 2011 Fcst
EGD	$411	$411	$425	$0	($14)
GD Affiliates					
Unregulated Storage	8	6	43		
Total GD capital	$472	$472	$518	($1)	($47)

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Next Steps

- Finance need to review with individual departments to get their buy-in
- Finance will continue to work even after CFO review in Sep to finalize reductions of O&M using the 5% reduction goal and 8+4 2011 reference
- The objective is to narrow the gap as much as possible by Nov 2011
- Departments are required to make a pitch to EMT to exceed 95% in the forecast

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Backup Slide

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EGD High Level Budget Assumptions

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	2012 Budget	2013 Budget	Change from LRP	
Accounting Standards	USGAAP	USGAAP	Y	CGAAP
Regulatory Economic Model	IR	COS	N	
Allowed ROE	Old ROE	New ROE	N	
Deemed Equity	36%	36%	N	
Regulatory Disallowance	RCAM vs. CAM	RCAM vs. CAM	N	
Earnings Target	LRP	LRP		

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GD Affiliate Budget Assumptions

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Financial Assumptions

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	2011 Fcst	2012 Budget	2013 Budget	2012 LRP	2013 LRP	Variance from 2012 LRP	Variance from 2013 LRP
IR Formula							
IR escalation factor	0.36%	0.77%		0.77%		0.00%	0.00%
Unlock customer growth	1.76%	0.98%		1.83%		-0.85%	0.00%
Revenue increase	2.12%	1.75%	8.82%	2.60%	8.10%	-0.85%	0.72%
Incremental margin ($m)	$17.3	$14.5	$88.2	$21.6	$82.0	($7.1)	$6.2
Distribution Volume							
Unlock customer	1,957,732	1,984,734	2,013,351	2,001,468	2,038,311	(16,734)	(24,960)
Volume throughput (bcf)	405	399	395	399	402	0	(7)
Average use in Rate 1 (m^3)	2,573	2,510	2,480	2,621	2,599	(111)	(119)
Weather - degree days	3,602	3,532	3,513	3,602	3,602	(70)	(89)

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EGD Key Financial Assumptions

2012 Budget

- Regulatory Recoveries
  - EGD pension funding contribution: $20.2m
  - Sewer lateral program: O&M $3.7m and Capital $1.6m
- Conservation programs & HST – carved out from ESM as a stand alone sharing at 50/50

2013 Budget

- Full recovery of all costs except for RCAM vs. CAM
- Depreciation rates: old rates are used (not reflect the new depreciation rates)
- Pension accounting: switch from the cash-based to accrual-based

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EGD Earnings Growth

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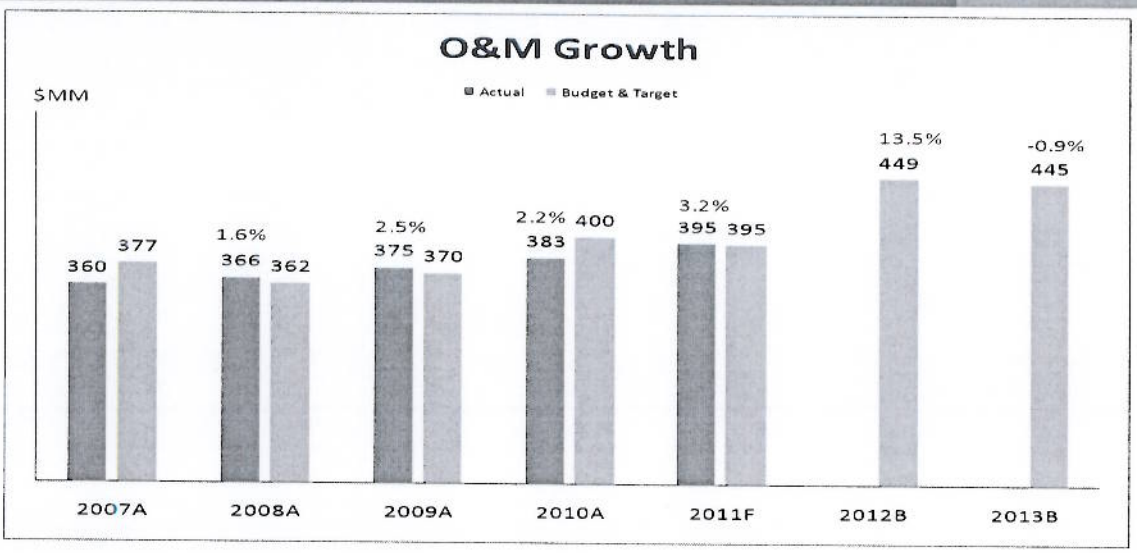
EGD O&M Growth



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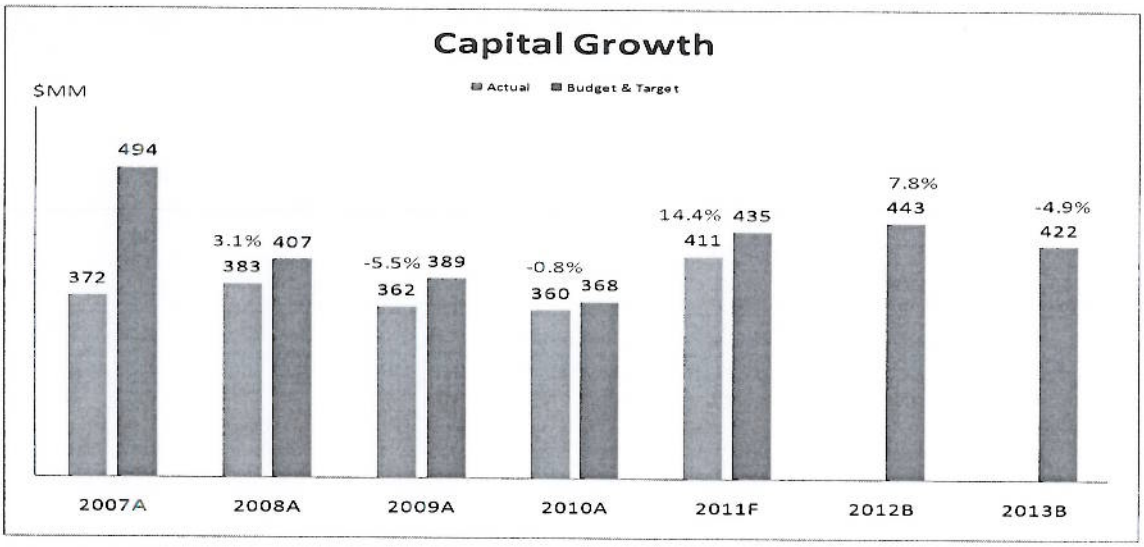
EGD Capital Growth



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EGD O&M Analysis (2012 vs. 2011)

2011 7&5 Forecast		**$395.4**	**% Incr(Decr)**
Cost Increases	**Incr(Decr)**		
Salaries, benefits and other	8.5		
Bad debts	5.0		
Safety requirements	4.3		
EI charges	3.0		
New regulations	2.6		
Inflationary pressure	2.6		
Customer growth in Ops	1.3		
BDCS growth programs	1.0		
Other	6.7		
		35.0	8.9%
Cost Decreases			
Productivity	(0.5)		
Higher A&G	(1.4)		
		(1.9)	-0.5%
Total Net Cost Increase before pension		**33.1**	**8.4%**
Pension funding contribution - Z-factor		20.7	5.2%
2012 Budget		**$449.2**	**13.6%**

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EGD O&M Analysis (2013 vs. 2012)

		$ million	
2012 Budget		**$449.2**	**% Incr(Decr)**
Cost Increases	**Incr(Decr)**		
Salaries, benefits and other	3.7		
BDCS growth programs	2.3		
Inflationary pressure	1.5		
Bad debt	0.6		
Customer growth in Ops	0.6		
Other	3.0		
		11.7	2.6%
Cost Decreases			
OPA- HPNC	(5.3)		
Higher A&G	(3.0)		
Productivity	(2.3)		
EI charges	(1.0)		
		(11.6)	-2.6%
Total Net Cost Increase before pension		**0.1**	**0.0%**
Pension funding contribution - Z-factor		(4.1)	
2013 Budget		**$445.2**	**-0.9%**

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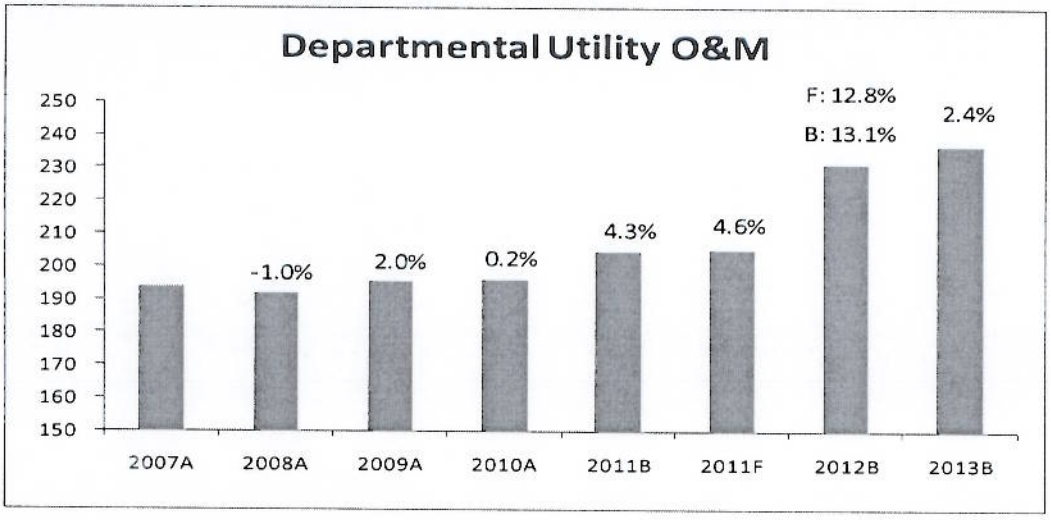
Departmental Utility O&M



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Utility O&M from Regulatory Perspective

$ million	COS Actual 2007	IR Actual 2008	IR Actual 2009	IR Actual 2010	IR Budget 2011	IR Forecast 2011	IR Budget 2012	COS Budget 2013
Utility O&M								
Customer care service charges	96.2	95.3	94.1	88.2	89.9	89.3	94.2	93.7
Corporate Costs Allocations	27.7	32.2	34.3	36.7	40.1	42.3	44.6	43.5
DSM	22.0	23.1	24.3	25.5	26.7	26.7	28.5	28.9
Other O&M (including A&G)	195.6	195.8	202.3	208.8	216.6	216.2	263.2	261.6
Utility O&M Total	341.5	346.3	355.0	359.2	373.4	374.6	430.4	427.6
Backout other O&M increase								
Growth projects from BDCS	-	-	-	-	-	-	0.6	2.5
HPNC1&2	-	2.0	4.0	8.4	7.8	7.4	6.5	1.3
CDM	0.2	0.1	0.0	0.0	0.4	0.2	0.6	0.8
Pension expense	1.5	1.7	2.6	4.2	3.9	3.5	24.2	20.1
Adjusted other O&M	193.9	191.9	195.8	196.1	204.6	205.1	231.3	236.9
Dept O&M increase		**-1.0%**	**2.0%**	**0.2%**	**4.3%**	**4.6%**	**12.8%**	**2.4%**

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O&M Opportunities from the Businesses

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$ millions	2011 7&5 Fcst	2012 Original Budget	O&M Opportunity	2012 Revised Budget	2012 Original vs. 2011	Opportunity as % of Original 2012 Budget
Operations	$60	$67		$67	11%	0%
BDCS (excluding OPA and DSM)	10	11	(0.4)	11	18%	4%
Customer Care	93	99	(0.9)	98	7%	1%
Pipeline Integrity & Safety	29	34	(1.6)	32	16%	5%
Risk Management	2	1		1	-29%	0%
Finance	6	7	(0.7)	6	14%	10%
IT	31	34		34	9%	0%
Energy Supply & Regulatory	13	14	(0.4)	13	6%	3%
Legal & Corporate Services	5	6		6	12%	0%
HR and Facilities	42	48	(2.6)	45	14%	5%
Public & Government Affairs	8	10	(0.7)	9	18%	7%
Corporate	24	24		24	0%	0%
Subtotal	**322**	**354**	(7.3)	**347**	**10%**	2.1%
Pensions	4	24		24	587%	0%
EI Charges	42	45		45	6%	0%
DSM	27	29		29	7%	0%
Ancillary Program Expenses	7	4		4	-37%	0%
Conservation Services (OPA and HPNC Program)	7	7		7	-1%	0%
Open Bill Access	13	14		14	6%	0%
A&G Capitalized and Rebillables	(26)	(28)		(28)	5%	0%
Total	**$395**	**$449**	($7.3)	$441	**14%**	1.6%

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2013 Budget Sensitivities

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Variable	+/-Δ	Earnings Impact ($m)
Equity	1%	4
ROE	1%	15
Ratebase	$50m	2
O&M	$10m	7

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2012 Risks

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Risks (Not probability weighted)

	$ millions	Pre-tax Amount	After-tax Amount
Risk 1	Pension funding contribution	($20.2)	($11.7)
Risk 2	Cross-bore program	(3.7)	(2.7)
Risk 3	Higher interest rates by 1%	(3.0)	(2.2)
Risk 4	Lower ROE for ESM by 30 bps	(6.0)	(4.4)
Risk 5	Lower ratebase for ESM by $100m	(4.6)	(3.4)
Risk 6	Lower earnings from GD affiliates		
	Total		

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2012 Potential Opportunities

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Opportunities (Not probability weighted)

$MM		Pre-tax Amount	After-tax Amount
Opp 1	Distribution margin	$6.0	$4.4
Opp 2	O&M savings at 5%	13.0	9.6
Opp 3	Income tax	2.7	2.0
Opp 4	Depreciation	2.0	2.0
Opp 5	Other revenue	1.0	0.7
	Total	**24.7**	**18.8**

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2012 Major Challenges

- Earnings gap is substantial
- Cost pressures from safety requirements and new regulations
- Scale back of green energy growth
- IR revenue increases by 1.8% as opposed to 6% increase in total expense
- One-time levers are limited

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Discussion Items and Recommendations

- O&M savings through cost control
  - Continue to scrub opportunities
  - Rationalize the timing of spending
- Match 2012 LRP capital by identifying the advancement opportunities to 2011
-

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EGD Capital Budget Profile

ENBRIDGE

$ millions	2011 7&5Fcst	2012 Budget	2013 Budget	2012 LRP	2013 LRP	Variance from 2012 LRP	Variance from 2013 LRP
EGD							
Customer Related Capital	74	79	87	79	86	-	1
System Improvements and Upgrades	67	84	79	83	83	1	(4)
Overheads	96	106	111	99	106	7	5
Cost of Retirements	16	12	11	15	13	(3)	(2)
General plant	37	61	64	51	44	10	20
Storage plant	30	22	14	23	13	(1)	1
LTC/Major Reinforcement Projects	7	14	21	12	36	2	(15)
Cast Iron Program	41	25	1	26	3	(1)	(2)
Cast Iron Program Cost of Retirements	10	13	8	11	7	2	1
Y-factor Power Generation	14	9	14	2	-	7	14
Oil and Gas	2	2	1	-	-	2	1
Energy Technology - Current Initiatives	-	-	-	3	6	(3)	(6)
BDCS Unidentified Growth	-	2	11	-	6	2	5
New Facilities (Markham training and other)	18	14	-	9	8	5	(8)
Capital Efficiency	-	-	-	(2)	-	2	-
Total EGD	**411**	**443**	**422**	**411**	**411**	**32**	**11**
Unregulated Storage Including IDC	43	5	37	5	37	-	-
EGD Including Unregulated Storage	**454**	**448**	**459**	**416**	**448**	**32**	**11**

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EGD O&M Budget by Department

ENBRIDGE

$ millions	2010 Actual	2011 7&5 Fcst	2012 Budget	2013 Budget	YOY Variance 2010 vs. 2011	YOY Variance 2011 vs. 2012	YOY Variance 2012 vs. 2013
Operations	$63	$60	$67	$68	-4%	11%	3%
BDCS (excluding OPA and DSM)	9	10	11	13	12%	18%	17%
Customer Care	91	93	99	103	2%	7%	4%
Pipeline Integrity & Safety	25	29	34	34	16%	16%	-1%
Risk Management	2	2	1	1	-23%	-29%	0%
Finance	6	6	7	7	5%	14%	1%
IT	30	31	34	36	2%	9%	6%
Energy Supply & Regulatory	13	13	14	14	4%	6%	1%
Legal & Corporate Services	1	5	6	6	250%	12%	4%
HR and Facilities	38	42	48	50	9%	14%	4%
Public & Government Affairs	8	8	10	10	1%	18%	-1%
Corporate	26	24	24	23	-9%	0%	-3%
Subtotal	**312**	**322**	354	**364**	**3%**	10%	**3%**
Pensions	4	4	24	20	-16%	587%	-17%
EI Charges	37	42	45	44	14%	6%	-2%
DSM	26	27	29	29	5%	7%	1%
Ancillary Program Expenses	7	7	4	3	-4%	-37%	-17%
Conservation Services (OPA and HPNC Program)	9	7	7	2	-23%	-1%	-70%
Open Bill Access	13	13	14	14	2%	6%	1%
A&G Capitalized and Rebillables	(24)	(26)	(28)	(32)	7%	5%	15%
Total	383	395	449	445	**3%**	**14%**	**-1%**
Controllable (42%)	**161**	**166**	**188**	**187**	3%	**14%**	**-1%**
Non-Controllable (58%)	**$222**	**$229**	**$260**	**$258**	3%	**14%**	**-1%**

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EGD FTEs

ENBRIDGE

	2011 Forecast	2012 Budget	2013 Budget	2012 LRP	2013 LRP	YOY Variance 2011F vs. 2012B	YOY Variance 2012B vs. 2013B
Finance	69	75	76	74	75	7	1
Customer Support	85	92	92	91	92	7	0
Energy Supply and Regulatory	52	55	55	53	54	3	-
Legal and Corporate Services	14	17	18	15	16	3	1
Operations	1,141	1,167	1,180	1,178	1,198	25	14
Information Services	167	174	180	180	190	7	6
Business Development & Customer Strategy	151	160	162	163	167	9	2
Human Resources	68	73	72	75	76	5	(1)
Pipeline Integrity and Safety	274	331	330	279	272	57	(1)
Public and Government Affairs	28	29	29	29	27	1	(0)
Corporate	16	16	16	14	14	-	-
Ancillary Operations (NGV)	5	5	5	5	5	0	(0)
Total EGD	2,070	2,195	2,217	2,156	2,186	125	22

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EGD
2013 Regulatory Budget
EMT Review #2

September 26th , 2011

ENBRIDGE

Agenda

ENBRIDGE

- Budget assumptions
- Budget inputs against the LRP
- Earnings profile
- Departmental utility O&M increase
- Capital spend trend
- Rate base growth
- Revenue requirements
- Cost of service earnings model
- Sensitivities
- EGD major challenges
- Conclusion

Budget Assumptions

- **Accounting standard**: USGAAP
- **Regulatory model**: Cost of Service
- **Regulatory recovery assumptions**: Full recovery of all costs except for the corporate cost disallowance
- **Deemed equity thickness**: 40% (vs. current 36%)
- **New ROE formula**: 9.66%
- **New depreciation rates**: slightly lower than the current rates
- **Pension accounting**: switch from the cash-based to accrual-based

Principal Budget Inputs

Cost of Service

Key Budget Inputs	2013 Budget	2013 LRP	2012 Budget	Variance from 2013 LRP	Variance from 2012 Budget	% Variance from 2013 LRP	% Variance from 2012 Budget	After tax change from LRP ($m)
Customer Adds	38,896	38,896	37,927	0	969	0.0%	2.6%	-
Capital Expenditures ($m)	$461	$411	$420	$50	$40	12.1%	9.6%	(3.0)
Ratebase	$4,161	$4,298	$4,038	-$137	$123	-3.2%	3.0%	-
Allowed ROE (New FRM) (1)	9.66%	10.04%	8.16%	-0.38%	1.50%	-3.8%	18.4%	(6.3)
Equity Thickness	40.0%	36.0%	36.00%	4.00%	4.00%	11.1%	11.1%	16.7
Natural Gas Price (US$/MMBTU) (2)	$4.52	$5.24	$4.52	($0.72)	$0.00	-13.7%	0.0%	(2.0)
								$5.4

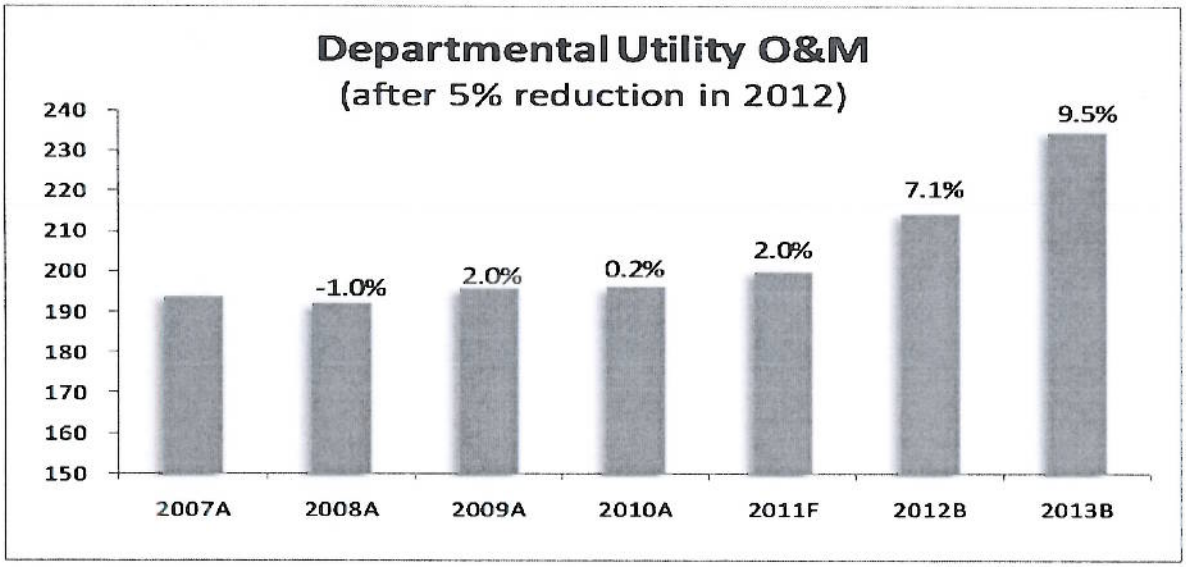
(1) Every 10 basis point change in allowed ROE translates into $1.7m change in earnings

(2) Nymex Henry Hub

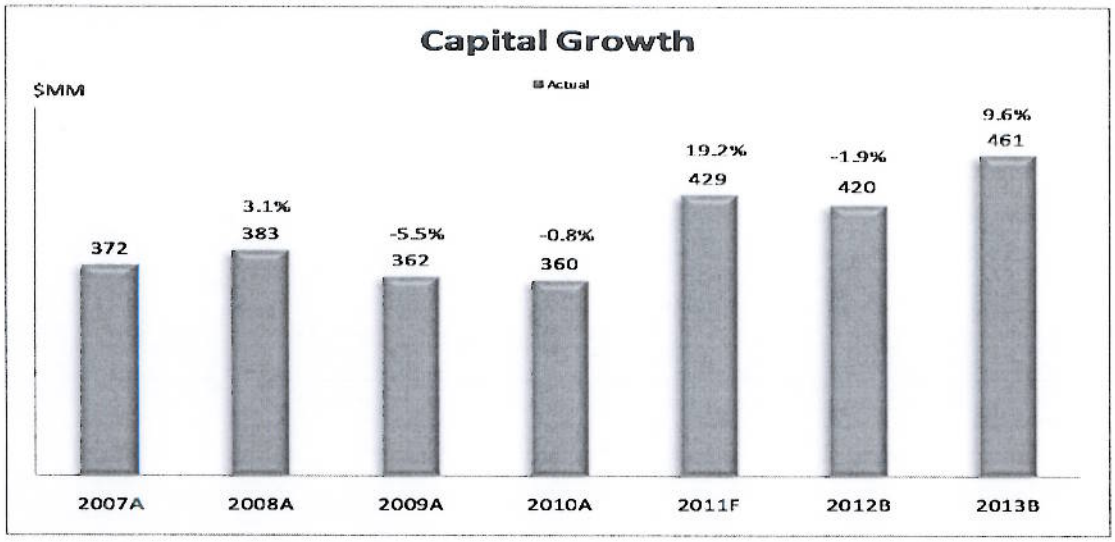
EGD Earnings Profile

$ millions	40% Budget	36% LRP	40% Adjust LRP	Variance from LRP 36%	Variance from LRP 40%
EGD LOB					
EGD Earnings - Base Case	$137	$133	$150	$4	($13)
Stretch - after Tax	-	17	17	(17)	(17)
EGD Earnings after Tax	**137**	**150**	**167**	**(12)**	**(29)**
GD Stretch LOB					
GD Stretch after-tax	-	4	4	(4)	(4)
Earnings including GD stretch	**$137**	**$153**	**$171**	**($16)**	**($33)**
Required Stretch after tax				16	33
Required Stretch before tax				$22	$44

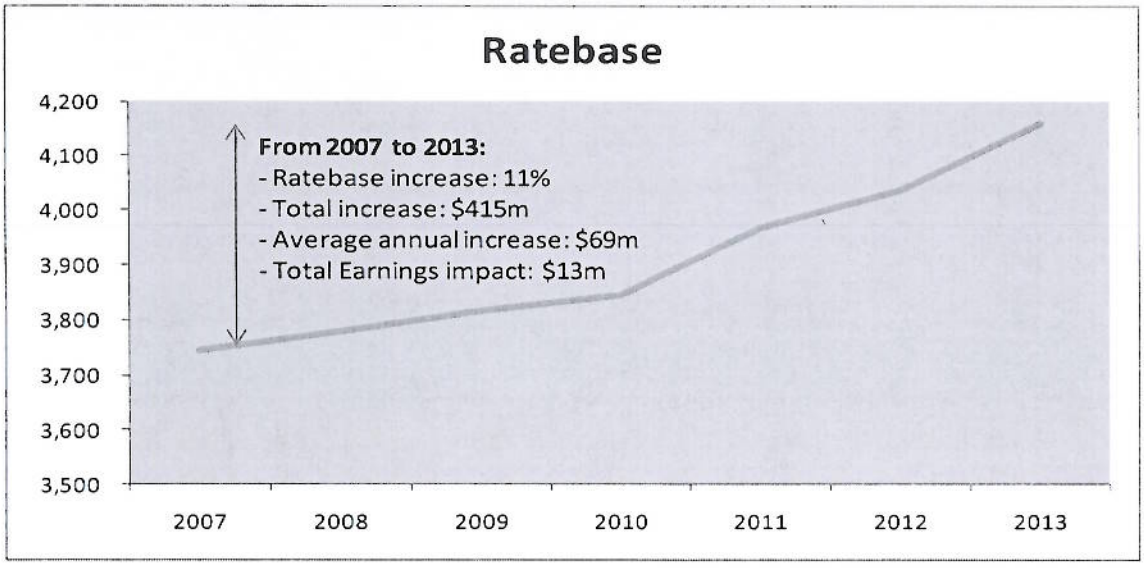
Departmental Utility O&M Increase



Capital Spend Trend



Rate Base Growth



Revenue Requirements

ENBRIDGE

$ millions	Revenue Requirements (Pre-tax)	Earnings Impact (After-tax)	
2007 Revenue Requirements	**$936**		Exclude notional utility account recovery of $9.2m
UDC in gas cost	75		New in 2013
New allowed ROE	26	19	Higher ROE of 1.27% (9.66% vs. 8.39%) vs. 2007
Higher equity thickness	22	16	40% vs. 36% in the base rates
Higher rate base	17	13	Higher ratebase results in higher deemed equity vs. 2007
O&M increase	92		Higher utility O&M including pension and OPEB accrual
Depreciation increase	73		Asset growth
Municipal tax	4		Higher asset base
Higher financing cost	8		To fund PP&E growth
Other revenue	(11)		Higher LPP, DPAC, CDM, and new revenue
Income Tax	(22)		Higher CCA and tax deduction
Return tax benefits to ratepayers	(42)		
Return refinancing benefits to ratepayers	(27)		
Other	8		
	221	**48**	
2013 Revenue Requirements	**$1,157**		
2008-2012 Revenue Requirements	**$105**		
Increase from 2012	**$116**		
% increase from 2012	**11.3%**		

Cost of Service Earnings Model

ENBRIDGE

($mm)	Budget 2013	Rates 2007	Variance
Ratebase	$4,161	$3,746	$415
Equity thickness	40%	36%	4%
Deemed Equity	1,664	1,348	316
OEB Allowed ROE	9.66%	8.39%	1.27%
Utility earnings before PPD	**161**	**113**	**48**
PPD	(17)	(15)	(2)
Utility earnings after PPD	**144**	**99**	**46**
Disallowance			
Regulatory disallowances	(14)		
Other disallowed amount			
Stretch			
Stretch to offset disallowances			
Stretch to deliver **25 bps ROE**			
Non-utility earnings			
EGD corporate earnings			
Earnings target	**153**		
Earrnings gap			

Sensitivities

Variable	+/-Δ	Revenue Requirement Impact ($m)	Earnings Impact ($m)
Allowed ROE	100 bps	22	17
Equity thickness	100 bps	5	4
Ratebase	$50m	3	2

EGD Major Challenges

- Double digit growth from 2012 for revenue requirements may result in significant rate increase in 2013
- The regulatory recovery outcomes are unpredictable
- The upside financial potentials are limited as all benefits are rebased in rates
- Downward pressures on allowed ROE and natural gas prices due to the recession concerns
- 2013 rates will be the base rates for next gen IR

Conclusion

ENBRIDGE

- Shall we file what we have or we need to revisit it?
- Need the EMT approval for the regulatory budget in order to move forward with the rate case application
- All the earnings gap issues will be addressed when 2013 corporate budget is developed in 2012

ENBRIDGE

Backup Slides

O&M by Department

$000's	2013 Budget	2012 Budget	2011 Fcst 8+4	2013 vs 2012	2012 vs 2011	13 vs 12 Incr (Decr) %	12 vs 11 Incr (Decr) %
Finance	7,784	6,926	6,394	857	532	12%	8%
Customer Support (includes bad debts)	102,110	96,374	87,299	5,736	9,075	6%	10%
ESSR	14,030	13,362	13,007	668	355	5%	3%
Legal and Corporate Services	5,661	5,462	4,800	199	662	4%	14%
Operations	68,015	63,498	59,517	4,517	3,981	7%	7%
Information Services (Adj EI)	34,607	32,112	29,805	2,495	2,307	8%	8%
BDCS (excluding DSM)	13,071	10,689	9,465	2,383	1,224	22%	13%
Human Resources (w/ OPEB adj)	55,938	45,185	41,577	10,753	3,608	24%	9%
Risk Management	1,183	1,102	1,656	81	(554)	7%	-33%
PIS	34,481	32,296	29,547	2,185	2,749	7%	9%
Public and Government Affairs	9,935	8,998	8,735	937	263	10%	3%
Corporate (not subject to 5% reduction)	23,408	21,435	25,474	1,973	(4,039)	9%	-16%
Sub Total	**370,223**	**337,438**	**317,276**	**32,786**	**20,162**	10%	6%
Pension (regular + additional contribution)	20,059	24,157	3,224	(4,098)	20,933	-17%	649%
DSM	28,924	28,495	26,708	429	1,787	2%	7%
Corporate Cost Allocations	44,677	45,827	42,607	(1,150)	3,219	-3%	8%
Ancillary Operations	3,414	4,079	6,337	(664)	(2,258)	-16%	-36%
Open Bill Access	14,054	13,885	13,082	170	803	1%	6%
Conservation Services (OPA&CDM)	2,051	7,139	6,958	(5,088)	180	-71%	3%
Amounts Relating to Capital Expenditures	(31,474)	(27,475)	(25,348)	(4,000)	(2,127)	15%	8%
Total Enbridge Gas Distribution	**461,929**	**433,646**	**390,844**	**18,386**	**42,700**	4%	11%

Capital Budget

$ millions	*2011 8&4Fcst*	*2012 Budget*	*2013 Budget*	*2012 LRP*	*2013 LRP*	*Variance from 2012 LRP*	*Variance from 2013 LRP*
EGD							
Customer Related Capital	75	78	87	79	86	(1)	1
System Improvements and Upgrades	71	80	79	83	83	(3)	(4)
Overheads	94	106	111	99	106	7	5
Cost of Retirements	11	12	11	15	13	(3)	(2)
General plant	47	52	66	51	44	1	22
Storage plant	32	23	20	23	13	0	7
LTC/Major Reinforcement Projects	5	2	33	12	36	(10)	(3)
GTA Reinforcement	2	10	19	-	-	10	19
Cast Iron Program	41	25	1	26	3	(1)	(2)
Cast Iron Program Cost of Retirements	10	13	8	11	7	2	1
Y-factor Power Generation	20	9	14	2	-	7	14
Oil and Gas	2	2	1	-	-	2	1
Energy Technology - Current Initiatives	-	-	-	3	6	(3)	(6)
BDCS Unidentified Growth	-	(0)	11	-	6	(0)	5
New Facilities (Markham training and other)	19	13	-	9	8	4	(8)
Capital Efficiency	-	(6)	-	(2)	-	(4)	-
Total EGD	**429**	**420**	**461**	**411**	**411**	**9**	**50**
Unregulated Storage Including IDC	43	5	38	5	37	0	1
EGD including Unregulated Storage	**471**	**426**	**498**	**416**	**448**	**9**	**50**

SEC INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 12

Please provide a table showing full-time headcount changes for each of the three employee categories in Table 5, on a monthly basis for actual 2011 through forecast 2013, as follows:

a. Retirements.

b. Other Voluntary terminations.

c. Involuntary terminations.

d. Replacement Hires

e. New Hires

f. Returns to work (maternity, disability, secondment, etc.)

RESPONSE

The table on the following page provides details as requested (on an annual basis), however it is not possible to provide replacement hires versus new hires as this information is only available at the time of the vacancy and is not available once the position has been filled. For 2012 and 2013 it is not possible to forecast retirements, terminations or returns from leave. EGD has not provided the quested information on a monthly basis in light of the effort that would be involved and the likelihood that information would not be easily available in that format.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

	2011 Actual Headcount		2012 Forecast FTE's	2013 Forecast FTE's
	Permanent	Temporary (includes Full time and Part time)		
Retirements				
Management	3			
Supervisory	33			
Union	24			
Total	60			
Other Voluntary terminations				
Management				
Supervisory	13	91		
Union	1	138		
Total	14	229		
Involuntary terminations				
Management	1			
Supervisory	7	3		
Union	9			
Total	17	3		
Hires/Rehires			FTE's	FTE's
Management	4		4	2
Supervisory	97	134	212	59
Union	26	144	47	(5)
Total	127	278	263	56
Returns to work				
Management	1			
Supervisory	25	2		
Union	36			
Total	62	2		

Witnesses: S. Kancharla
R. Lei
S. Trozzi

SEC INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 12

Please explain the main demographic or other factors that result in unionized employees reducing by 60 FTEs, or 7.9%, from 2007 to 2013, while non-unionized employees are increasing by 386 FTEs, or 32.0%, over the same period.

RESPONSE

Please refer to Full Time Equivalents table provided in response to Board Staff Interrogatory#5 at Exhibit I, Issue D1, Schedule 1.5, page 2.

Total unionized actual FTE's for 2007 was 728 while 2013 budget is 695. The decrease of 33 or 4.5% is due to the following:

1) through attrition the Company has reduced some field positions for work that is no longer required, and
2) 2013 budget includes vacancies while 2007 actuals do not include vacancies

The non-unionized FTE's for 2007 was 1,212, without vacancies while 2013 budget is 1,592, with vacancies. If vacancies were added back to 2007 FTE's (based on percentage of total FTE's) the number would be 1,293. The 2013 budget FTE increased by 299 or 23.1% compared to restated 2007.

The increase in supervisory and management roles is attributed to repatriation of large volume billing and joint utility trench groups as well as the heightened focus on safety and pipeline integrity. This has resulted in additional supervisory and management positions in such areas as, pipeline evaluation and inspection, damage prevention, environmental health and safety, safety and technical training, GTA reinforcement project and safety supervisors.

These positions are not unionized due to the requirements of the role, such as the need for a professional designation or a people leader or a quality control function.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

SEC INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 18

Please provide further details with respect to line 58, including the nature of the costs and the results achieved. Please provide any business case or proposal relating to the initiative, and any report or reports dealing with its results.

RESPONSE

In response to Line 58 “The Company’s performance management initiative aimed at improving overall efficiency and effectiveness”, the nature of the 2013 increase over 2012 Bridge Year of $1.3 million is in payment for severance expenses. The Company is placing a greater emphasis on performance management ensuring employees are achieving the required results. Employees are expected to achieve their performance objectives, which assists the Company in achieving financial and operational results. As the performance management process continues to be refined and leaders receive additional training and education Enbridge expects severances to increase over the next two or three years.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

SEC INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 20

Please advise whether the $6.2 million annual increase in advertising is expected to be a permanent increase. If so, please provide the business case or other proposal relating to the initiative. If not, please provide a table showing the incremental (relative to 2011) advertising in this category expected in each year from 2012 through 2016.

RESPONSE

Budgets and budget information beyond the Test Year are not yet available. Future plans will be determined after research is conducted to measure the effectiveness of current activities and to reflect the needs of the business.

As described in evidence at Exhibit D1, Tab 21, Schedule 1, Enbridge plans additional communication and other community outreach initiatives that relate to core messages around safety, including targeted audiences such as seniors and schools.

Safety is a priority for the Company and its employees and by extension raising customer awareness about safety is of critical importance. Plans include continued communication outreach through media including radio and potentially new outlets such as transit and cinema, as well as increased use of social and electronic media including video and website. Agency support will be used to assist with the development of new safety initiatives including the new or updated safety program material for key groups including first responders, seniors and schools and outreach to community media in the Company's more than 100 franchise communities.

The target is to improve customer satisfaction regarding our safety communications given that research indicates that only 42% of the Company's customers rate the quality

Witnesses: S. Kancharla
R. Lei
C. Meyer
M. Sousa

of safety communications as excellent or very good. The themes of these important public safety messages will be related to topics including carbon monoxide detection, call before you dig reminders, smell of gas, sewer safety and, particularly in rural areas, appropriate customer responses to natural gas meter and regulator safety following large snowfalls.

Further, a portion of the increase targets areas within Enbridge's franchise territories that do not see the same level of communication and media safety initiatives as traditionally occurs within the urban centres.

Witnesses: S. Kancharla
R. Lei
C. Meyer
M. Sousa

SEC INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/1, p. 29

Please confirm that Utility O&M per customer increased by 1.1% over the period 2004 to 2011, but the Applicant is currently proposing to increase Utility O&M per customer by 18.2% from 2011 to 2013.

RESPONSE

Yes. Utility O&M per customer in nominal dollars increased by 1.1% over the period 2004 to 2011, and 18.2% from 2011 to 2013.

The increase from 2011 to 2013 is primarily resulting from pension expense, customer care costs, and safety related spending.

By excluding pension expense, customer care costs, and safety related spending, 2013 increases by 0.8% from 2011 in nominal dollars but decreases by 2.5% in constant dollars.

Also, please refer to Board Staff Interrogatory #16 at Exhibit I, Issue D1, Schedule 16, for the cost driver analysis of O&M cost per customer over the period 2007 to 2013.

Witnesses: S. Kancharla
R. Lei

SEC INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Ref: D1/3/2, p. 9

Please expand Table 1 to include historic figures for each of 2007 through 2010.

RESPONSE

The table below indicates the historic figures for each category for 2007 through 2010.

Particulars ($M)	2013 Forecast	2012 Estimate	2011 Actual	2010 Actual	2009 Actual	2008 Actual	2007 Actual
Salaries and Wages	186.0	176.6	150.6	139.8	132.9	131.8	128.9
Short Term Incentive Pay	20.3	19.4	25.2	19.7	25.3	19.1	20.1
Benefits	30.5	25.9	24.3	22.9	22.8	22.0	24.4
Pension	37.3	20.6	3.2	4.0	2.6	1.7	1.5
Training and Development	2.7	2.6	2.4	1.5	1.2	1.6	0.8
Awards and Allowances	1.3	1.3	1.7	1.3	1.3	0.9	1.3
Relocation	0.5	0.5	2.3	0.5	0.8	0.6	0.5
Severances	2.0	1.0	2.0	2.4	0.8	3.2	0.9
FTE's *	2,287	2,231	2,084	1,947	1,884	1,943	2,070

*FTE's include vacancies for 2007 through to 2011.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit A2 Tab 1 Schedule 1

a) Please update the O&M per customer table page 17 to reflect actual data for 2011.

RESPONSE

Please refer to Exhibit D1, Tab 3, Schedule 1, Updated: 2012-06-01, page 29, Table 6 for the 2011 actual data.

Witnesses: R. Bourke
R. Lei

VECC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1 Tab 25 Schedule 1

a) Please update Table 1 to include actual data for 2011.

RESPONSE

a) Table 1: SQR Targets Vs. Actuals is updated below with 2011 data

Service Quality Requirement	Target	2009	2010	2011
Appointments Met Within the Designated Time Period	85.0%	96.3%	94.7%	95.3%
Emergency Calls Responded within One Hour	90.0%	96.2%	94.2%	95.2%
Time to Reschedule Missed Appointments	100.0%	97.6%	95.2%	92.8%
Number of Days to Reconnect a Customer	85.0%	94.3%	93.9%	93.8%
Call Answering Service Level	75.0%	74.1%	65.3%	75.2%
Number of Calls Abandon Rate	10.0%	7.0%	11.6%	4.1%
Meter Reading Performance	0.50%	0.47%	0.66%	0.7%
Number of Days to Provide a Written Response	80.0%	89.0%	N/A	N/A

Witnesses: T. Ferguson
K. Lakatos-Hayward
M. Torriano
M. Wagle

VECC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

Reference: Exhibit D1 Tab 3 Schedule 1

a) Please expand Table 4 -Other O&M, to breakout Salaries and Wages, Benefits and Pension Costs.

RESPONSE

Please refer to Line No. 4 for Pension Costs on the updated Table 4 provided below:

Table 4
Enbridge Gas Distribution
Summary of Operating and Maintenance Expense by Category
2013 Budget, 2012 Estimate, 2011-2007 Actual, and 2007 Board Approved

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.	Categories ($ Millions)	Budget 2013	Estimate 2012	Actual 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007	Board Approved 2007
1.	Customer Care Service Charges	$89.4	$90.4	$79.2	$87.5	$87.5	$82.5	$84.4	$90.8
2.	Regulatory Cost Allocation Methodology(RCAM)	32.1	30.2	26.7	24.3	21.2	19.1	18.1	18.1
3.	Demand Side Management (DSM)	31.4	28.1	26.7	25.5	24.3	23.1	22.0	22.0
4.	Pension Expense	37.3	20.6	3.2	4.0	2.6	1.7	1.5	1.7
5.	Other O&M	247.8	232.9	224.7	205.5	201.5	197.0	196.0	193.6
6.	Total Net Utility O&M Expense	$438.1	$402.2	$360.5	$346.7	$337.0	$323.4	$322.0	$326.2

Witnesses: S. Kancharla
R. Lei
S. Trozzi

The breakout of Salaries and Wages, Benefits in Other O&M are as follows:

Line No.	Particulars ($ million's)	Budget 2013	Estimate 2012	Actual 2011	Actual 2010	Actual 2009	Actuals 2008	Actual 2007	Board Approved 2007
1.	Salaries and Wages	$170.9	$160.7	$141.5	$133.8	$125.1	$127.0	$127.1	$136.5
2.	Benefits	30.5	25.9	24.3	22.9	22.8	22.0	24.4	21.3

Witnesses: S. Kancharla
R. Lei
S. Trozzi

VECC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

References: Exhibit D1 Tab 3 Schedule 2 Page 2
Exhibit D2 Tab 3 Schedule 1

a) For each of the 4 employee categories –Executive, Management, Supervisory and Union, please provide a continuity schedule that shows 2007-2013F for the following categories of compensation/payroll costs:

FTEs
Base Pay
Bonus/ Incentive STIP and/or LTIP
Total cash compensation
Benefits
Pension

b) For Total Cash Compensation please show the year over year increase for each category and calculate the Compound Annual Growth Rate (CAGR).

c) What is the impact on the test year revenue requirement if non-union increases are limited to 2.0% in 2013?

RESPONSE

a) See table on the following page for an outline of FTEs and Base Pay by category of employees, Management, Supervisory and Union. STIP, LTIP, Benefits and Pension cannot be broken down by employee category due to the manual effort and time involved. LTIP is granted to management employees only. The Company is not able to place a value on the grants issued as it would be reflective of the stock price on the day of payout. Please refer to VECC Interrogatory #4 at Exhibit I, Issue DI, Schedule 20.4 for an outline of LTIPs awarded 2007 through to 2013F.

Witnesses: S. Kancharla
R. Lei

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Budget
FTE (without vacancies) (units)							
Management	100	113	118	126	134	138	140
Supervisory	1,112	1,098	1,058	1,087	1,181	1,393	1,452
Union	728	681	662	661	653	700	695
Total FTE	1,940	1,892	1,838	1,874	1,968	2,231	2,287
Base Pay ($ thousands)							
Management	12,593	14,758	16,079	17,612	19,452	21,056	21,911
Supervisory	77,189	79,018	78,882	83,387	91,656	111,562	119,216
Union	39,125	38,035	37,905	38,822	39,494	43,932	44,861
Total Base Pay	128,906	131,811	132,866	139,821	150,602	176,550	185,988
STIP	20,084	19,109	25,303	19,681	25,206	19,428	20,257
Benefits	24,390	22,047	22,770	22,864	24,263	25,941	30,452
Pensions	1,499	1,749	2,570	3,994	3,225	20,557	37,300

Witnesses: S. Kancharla
R. Lei

b) Total Cash Compensation for year over year increases cannot be identified by employee category due to the manual effort involved in identifying STIP by employee category. Total Cash Compensation includes base pay and STIP as follows:

2008 $000	2009 $000	2010 $000	2011 $000	2012 Estimate $000	2013 Budget $000
$1,930	7,248	1,333	16,306	20,170	10,267

Compound Annual Growth Rate ("CAGR") is 5.6%. However, this calculation does not take into consideration the increase in FTE's and therefore, is a misleading indicator of the average employee's cash compensation over this period of time.

A more accurate calculation is to use the year over year increase per FTE. This results in a Compound Annual Growth Rate of 2.7%.

c) Refer to Energy Probe Interrogatory #5 at Exhibit I, Issue D1, Schedule 7.5.

Witnesses: S. Kancharla
R. Lei

VECC INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 1: Is the 2013 O&M budget appropriate?

References: Exhibit D1 Tab 3 Schedule 2 Page 2
Exhibit D2 Tab 3 Schedule 1

a) Please provide Details of LTIP Costs 2007-2013F

Incumbents
Number of stock units by type and
Cash Equivalent value(s)

b) Reconcile LTIP Costs to SBC amounts charged under CAM and RCAM (Exhibit D1 Tab 4 Schedule 1 Attachment 1)

RESPONSE

a) LTIP for executives include the performance stock unit plan ("PSU"), the incentive stock option plan ("ISO") and the performance stock option plan ("PSO"). The Company also has a restricted stock unit plan ("RSU") for middle management.

The table below outlines the LTIP units granted and their corresponding values from 2007 to 2013F by LTIP type. LTIP is awarded at the beginning of the year as its purpose is related to employee retention. The Company is not able to forecast market value and sum of share unit grants.

Witnesses: S. Trozzi
Mercers Consultant

Restricted Stock Units

Grant Year	Currency	Market Value of Securities underlying Share Units on the Date of the Grant	**Sum of Share Units Granted**
2007	CAD	$20.12	85,300
2008	CAD	$19.39	109,200
2009	CAD	$19.36	134,200
2010	CAD	$23.62	121,800
2011	CAD	$27.92	112,900
2012	CAD	$36.38	97,900
2013F	CAD		

Performance Stock Units

Grant Year	Currency	Market Value of Securities underlying Share Units on the Date of the Grant	Sum of Share Units Granted
2007	CAD	$20.12	9,600
2008	CAD	$19.39	10,000
2009	CAD	$19.36	13,600
2010	CAD	$23.62	17,200
2011	CAD	$27.92	18,000
2012	CAD	$36.38	16,050
2013F	CAD		

Incentive Stock Options

Grant Year	Currency	Fair Value of Options on the Date of the Grant	Sum of Share Units Granted
2007	CAD	$3.60	231,600
2007	USD	$3.10	10,400
2008	CAD	$2.91	415,600
2009	CAD	$3.37	501,200
2010	CAD	$3.28	353,000
2010	USD	$4.00	6,000
2011	CAD	$4.00	548,000
2011	USD	$5.11	8,200
2012	CAD	$5.00	467,400
2013F	CAD		

b) LTIP Costs, RCAM and CAM

	2013 Estimate		2012		2011		2010		2009		2008		2007	
Grant														
LTIP	N/A		$6.5M		$5.9M		$4.5M		$4.6M		$3.6M		$2.7M	
Expense														
RCAM (EGD direct)	$7.7M	**	$7.5M	*	$6.4M	*	$4.8M	*	$4.3M	*	$3.1M	*	$1.7M	*
CAM (EGD direct)	$7.7M	**	$7.5M	*	$7.5M		$5.6M		$4.9M		$4.2M		$2.4M	
CAM (allocation)	$5.3M	**	$5.2M	*	$5.7M		$4.6M		$4.3M		$3.3M		$1.5M	
CAM (total)	$13.0M		$12.7M		$13.2M		$10.2M		$9.2M		$7.6M		$3.9M	

* Budget
** Estimate

Witnesses: S. Trozzi
Mercers Consultant

The amounts in CAM/RCAM expense cannot be easily reconciled to LTIP as LTIP costs represent dollars granted, whereas RCAM and CAM amounts represent dollars expensed. At a high level, differences can be summarized as folows:

1. RCAM is budget based, whereas CAM numbers are actual (to 2011)

2. RCAM SBC line item only includes EGD's direct SBC amount, whereas total CAM charges include an allocation of costs with respect to employees of EI providing services to the Company

3. LTIP granted are amortized and expensed over a number of years as reflected in CAM/RCAM amounts.

Witnesses: S. Trozzi
Mercers Consultant

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Ref: Ex. D1/T2/S1/p2

With respect to Delivered Supply Enbridge states that, "These supplies are forecasted to be acquired directly at Dawn. However, the Company may consider alternative sources such as western Canadian supply utilizing TCPL STFT capacity either for economic or operational reasons…"

a) Does the Enbridge forecast of 52.2 Bcf for Delivered Supply during the test year include anything other than supplies acquired directly at Dawn? If there are alternative sources of supply, indicate why such alternative arrangements would be in the interests of ratepayers?

b) Describe what economic or operational reasons might cause Enbridge to consider the alternative sources of delivered supply.

c) Has Enbridge forecasted its gas costs making use of any projects alternative sources as contemplated above? What effect would this have on the gas costs portfolio in terms of risks with respect to pricing, security of supply, and volatility?

RESPONSE

The 52.2 Bcf identified as Delivered Supply on Exhibit D3, Tab 3, Schedule 1 is assumed to be acquired directly at Dawn.

Enbridge has developed its 2013 Gas Supply portfolio and the associated gas cost forecast assuming the above mentioned gas supplies are acquired at Dawn. If, however, alternative supply options such as discounted transportation or increased access to non-traditional supply basins such as Marcellus become available prior to the start of or during the 2013 Fiscal year the Company believes that those opportunities

Witnesses: J. Sarnovsky
D. Small

should be reviewed and if deemed beneficial then alternative arrangements should be made.

While a comparison of the forecasted pricing index of two supply alternatives will provide the economic analysis needed to choose one source of supply over the other, it is not always the only determining factor. First and foremost the Company will want to ensure security of supply of the potential options. Geographical diversity is another element that the Company will consider incorporating: such diversity could mitigate both the price volatility of a particular supply source as well as the operational risk associated with a single shipper.

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Ref: Ex. D1/T2/S1/p4/para11

Enbridge states that, "The Company believes that the failure to deliver during periods of high demand in January and February 2011 are justification to maintain the same level of Peaking Supplies for 2013 as was forecast for 2012."

a) It would appear that Enbridge is basing its forecast requirements for 2013 on one year, 2011. Please explain why this is a prudent approach.

b) Please provide a summary of failures to deliver of equivalent or worse severity to the January 2011 and February 2011 failures to deliver dating back to 2007.

RESPONSE

During the 2012 proceeding Enbridge went to great lengths to justify its supply plan which included a forecasted level of peaking service that the Board ultimately approved as part of its decision. There has been no change in circumstances that would lead Enbridge to believe that peaking service has become any more reliable for 2013 than was contemplated for 2012. Therefore the Company has prepared its 2013 forecast using the same level of peaking service as 2012.

There have been no delivery failures of equivalent or worse severity dating back to 2007. However, this is an issue that the Company first expressed concern about in its 2009 Rate Case and became one of the topics for discussion in the System Reliability consultative. The Company believes this issue should not be discounted because of what may or may not have happened five years ago and remains something that needs to be addressed as part of the Company's supply portfolio and its obligation to provide safe and reliable natural gas.

Since the development of its evidence for 2013 there have been new pieces of information that have come to light which either further support the Company's decision

Witnesses: J. Sarnovsky
D. Small

to assume the utilization of STFT in place of traditional peaking supplies and/or which could potentially lead to the development of supply and transportation options other than traditional western Canadian supplies and long haul transportation over the short term.

In its Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013 application, TransCanada recently provided an updated throughput forecast. Relative to its original forecast, TransCanada is now projecting approximately 1 Bcf/d, on average, less western Canadian receipts on the Mainline. The decline in throughput from the original filing relative to the updated filing is due in part to a reduction in discretionary flows on the Mainline. This is of concern because the reduction in discretionary flows will lower liquidity on the Mainline which is a primary source of peaking supplies, thereby decreasing the availability of peaking supplies and potentially reducing the reliability of these supplies even further.

Also included in this updated throughput forecast is the recognition of LNG infrastructure development and the associated impacts on western Canadian flows. While not expected to impact supplies in the near term, the development of LNG infrastructure over the longer term has the potential to pull gas away from the Mainline, further reducing the amount of gas available for export to eastern markets over the longer term. Lower availability of western Canadian supply will require continued evaluation of other sources of supply and transportation to meet natural gas demand as tolls for long haul transportation escalate and traditional peaking supplies continue to be unsecured.

TCPL has also stated publicly that they are stopping integrity work on segments of the Mainline which will lower capacity.

While western Canadian supplies are projected to decline, supplies closer to eastern Canadian markets are expected to become an increasingly important supply source. Recent open seasons run by TransCanada have resulted in a s58 application with the NEB to expand existing infrastructure to allow flows from the Northeastern US back into Canada. This expansion will allow eastern Canadian market access to Marcellus and potentially other supplies from the US. TransCanada recently held a second open season requesting interest in service from Niagara and other points on the Mainline. In addition, several projects in the US have or will eventually provide increased transportation capacity from the emerging Marcellus basin to Ontario.

Witnesses: J. Sarnovsky
D. Small

BOMA INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Ref: Exhibit D2, Tab 6, Schedule 1, page 3 of 18.

With respect to the statement: "An article from the AGA likewise stated that the primary cause of UAF is meter uncertainty", has Enbridge done or is Enbridge aware of any studies comparing meter uncertainty between Canada under Measurement Canada and the United States under the National Institute of Standards and Technology (NIST)?

RESPONSE

By virtue of operating in Canada, the Company has to be compliant with Measurement Canada requirements. The Company has not conducted studies comparing meter uncertainty between Canada under Measurement Canada and the United States under the National Institute of Standards and Technology ("NIST"). Further, the Company is not aware of any studies conducted with respect to this area.

The Company does benchmark its metering process with respect to measurement variability with other gas utilities in both Canada and the United States as stated at paragraph 21, page 8 of Exhibit D2, Tab 6, Schedule 1 as follows:

> To summarize measurement and variability considerations, the Company is in compliance with Measurement Canada requirements and benchmarks its metering process with respect to measurement variability with other gas utilities. The Company is one of the Measurement Canada accredited service providers. Accredited organizations are those organizations that have been delegated authority to inspect devices on behalf of Measurement Canada pursuant to the Electricity and Gas inspection Act. Enbridge is also one of the few organizations can provide more than two inspection type services.[1] Moreover, the Company set its meter accuracy policy to have lower tolerance level than the standard prescribed by Measurement Canada for new and re-worked meters. Finally, the Company uses its check meters to monitor the accuracy of custody transfer meters maintained by third party transmission pipelines to ensure metering variations are within the industry standard of +/-2% tolerance.

[1] http://corporations.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm00527.html#Enbridgee

Witness: I. Chan

CME INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: Exhibit D1, Tab 2, Schedule 1original and updated
Exhibit D3, Tab 3, Schedules 1 to 5

1) What differences, if any, will there be in EGD's 2013 gas supply plan if its proposed changes to Peak Gas Day Design Criteria ("PGDDC") are either rejected completely or postponed for consideration some time before the end of 2013?

RESPONSE

As outlined at Exhibit D1, Tab 2, Schedule 1, page 3, Paragraph 10 the Company has prepared its 2013 Gas Cost Budget assuming continuation of the existing Design Criteria HDD values. There would be no changes to the Company's 2013 gas supply plan if its proposed changes to Peak Gas Day Design Criteria are postponed for consideration some time before the end of 2013. If the proposed changes to Peak Gas Day Design Criteria are completely rejected the Design Day Criteria Transportation Deferral Account would not be required.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

CME INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: Exhibit D1, Tab 2, Schedule 1original and updated
Exhibit D3, Tab 3, Schedules 1 to 5

1) Is EGD forecasting any UDC on the TCPL system in 2013? If so, then please explain why EGD cannot structure its upstream transportation arrangements with TCPL in a way to entirely avoid UDC having regard to the excess TCPL capacity that currently exists and the broad range of flexible transportation services that TCPL offers.

RESPONSE

Enbridge continues to utilize 100% of its contracted long haul FT TCPL capacity from Empress, thereby avoiding UDC.

Enbridge has included in its 2013 supply portfolio 75,000 GJ's/day of STFT for the period of January to March. The purpose of the STFT is to help meet the forecasted peak day demand. Because actual peak day cannot be predicted and there are no assurances that this level of transportation capacity would be available for a shorter period of time, it is necessary to contract for this level of service during the above mentioned months. The Company will then have this service available to assist with meeting winter demand when it is not required on the peak day. As discussed in its pre-filed evidence the Company is forecasting to meet its Peak Day requirement in 2013 in a manner similar to 2012 which included 75,000 GJ's/day of STFT. The forecasted winter demand for 2013 however is lower than in 2012 and as a consequence not all of the 75,000 GJ's/day of STFT will be utilized on non-peak days. This will represent unutilized capacity costs that the Company is forecasting to be $2.8 million assuming current TCPL tolls and assuming no other alternative service becomes available.

The current excess capacity on TCPL and broad range of services identified above are discretionary services and are generally not available on peak day. The Company cannot and should not plan to meet its peak day requirements assuming the use of interruptible service and is required to contract for firm services such as FT or STFT.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Since the development of its evidence for 2013 there have been new pieces of information that have come to light which either further support the Company's decision to assume the utilization of STFT in place of traditional peaking supplies and/or which could potentially lead to the development of supply and transportation options other than traditional western Canadian supplies and long haul transportation over the short term.

In its Business and Services Restructuring Proposal and Mainline Final Tolls for 2012 and 2013 application, TransCanada recently provided an updated throughput forecast. Relative to its original forecast TransCanada is now projecting approximately 1 Bcf/d, on average, less western Canadian receipts on the Mainline. The decline in throughput from the original filing relative to the updated filing is due in part to a reduction in discretionary flows on the Mainline. This is of concern because the reduction in discretionary flows will lower liquidity on the Mainline which is a primary source of peaking supplies, thereby decreasing the availability of peaking supplies and potentially reducing the reliability of these supplies even further.

TCPL has also stated publicly that they are stopping integrity work on segments of the Mainline which will lower capacity.

Also included in this updated throughput forecast is the recognition of LNG infrastructure development and the associated impacts on western Canadian flows. While not expected to impact supplies in the near term, the development of LNG infrastructure over the longer term has the potential to pull gas away from the Mainline, further reducing the amount of gas available for export to eastern markets over the longer term. Lower availability of western Canadian supply will require continued evaluation of other sources of supply and transportation to meet natural gas demand as tolls for long haul transportation escalate and traditional peaking supplies continue to be unsecured.

While western Canadian supplies are projected to decline, supplies closer to eastern Canadian markets are expected to become an increasingly important supply source. Recent open seasons run by TransCanada have resulted in a s58 application with the NEB to expand existing infrastructure to allow flows from the Northeastern US back into Canada. This expansion will allow eastern Canadian market access to Marcellus and potentially other supplies from the US. TransCanada recently held a second open season requesting interest in service from Niagara and other points on the Mainline. In addition, several projects in the US have or will eventually provide increased transportation capacity from the emerging Marcellus basin to Ontario.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

CME INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: Exhibit D1, Tab 2, Schedule 1original and updated
Exhibit D3, Tab 3, Schedules 1 to 5

1) The evidence indicates that EGD now acquires storage from Union under the auspices of market-based rates that are in decline because of changing natural gas market dynamics. Please produce, in confidence if necessary, the contract that EGD recently negotiated with Union for storage capacity and services under the auspices of market-based rates.

RESPONSE

The evidence at Exhibit D1, Tab 2, Schedule 1, page 7 discusses how the Company held an entitlement of storage with Union Gas that was broken down into three contracts based on cost of service rates with varying expiry dates. As the contracts expired (10,000,000 GJ's expiry March 31/08, 6,000,000 GJ's expiry March 31/09, 5,260,000 GJ's expiry March 31/10) the Company acquired replacement storage from third parties (including Union Gas) at Market Based pricing through an RFP process such that the replacement contracts are with multiple providers at varying terms and conditions. These varying conditions include the size of the storage capacity, injection/withdrawal capabilities, operational flexibility i.e., the ability to nominate intra-day and the length of term of the contract. For an explanation of the RFP process see the response to FRPO Interrogatory #4 at Exhibit I, Issue D2, Schedule 8 4. Currently, as of April 1, 2012, the Company has six different storage contracts that include four separate contracts with Union Gas.

The Company respectfully declines to produce the most recent contract with Union Gas for two reasons: 1) to maintain the integrity of the RFP process and 2) a snap shot of one contract in isolation would not demonstrate the point the Company was trying to make in its evidence which is that since the inception of Market Based pricing, Enbridge has seen an overall decline in the prices paid for storage service. The one exception was for storage service effective April 1, 2010 from a counterparty that offered high

Witnesses: J. Denomy
J. Sarnovsky
D. Small

deliverability storage which came at a slight premium compared to a standard service storage arrangement.

Listed below are the average unit rates ($/Gj) payable for market based storage service obtained as part of the RFP process for every year beginning with April 1, 2008:

April 1, 2008	1.11
April 1, 2009	0.97
April 1, 2010	1.15
April 1, 2011	0.79
April 1, 2012	0.54

Witnesses: J. Denomy
J. Sarnovsky
D. Small

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Ref: D1/T2/S1/p. 6

The evidence states that the impact on 2013 gas costs of the long-haul STFT on TCPL of additional firm transportation would be an incremental $66.2 million or $74.5 million of unutilized transportation cost impacts in total. Please explain, in detail how those amounts were calculated. Please include all assumptions. Please identify how those costs would be recovered from customers (system vs. direct purchase, rate classes etc.)

RESPONSE

Based on the updated forecast, the Company is assuming that under the current design day criteria there will be $2.8 million of unutilized capacity cost consequences which is based on a level of unutilized STFT capacity of 1.3 PJ at the current TCPL toll. If the Board were to accept the Company's proposed change in Design Day Criteria and the only way to satisfy that increase in gas supply requirements was with STFT then the amount of unutilized capacity increases to 32.7 PJ at a cost of $69.0 million or an increase of $66.2 million.

The STFT is used to satisfy demand in peak and near-peak conditions. The cost consequences of STFT are allocated to all bundled customer classes using the deliverability allocator (i.e. rate class demand in excess of its average winter demand). These costs are recovered in rates through load balancing charges from all bundled customers (system gas and direct purchase customers). Customers within the same rate class pay the same unit rate for these costs.

Witnesses: J. Denomy
A. Kacicnik
J. Sarnovsky
D. Small

FRPO INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1,

Please update the gas supply forecast using the OEB approved forecast for July 1, 2012.

a. Please highlight the major changes in cost identified in the revised forecast.

b. Please detail how the proposed costs for the non-commodity components of the Gas Supply plan with the updated commodity costs.

c. Does EGD forecast any planned UDC?

RESPONSE

a) and b)

The Company is not prepared to update either its 2013 Gas Cost forecast or its 2013 Revenue forecast for the Board approved July 1, 2012 QRAM. An update using July 1, 2012 QRAM prices will not provide any further meaning to the application as the prices for 2013 and all related consequences will be applied for and approved in the January 1, 2013 QRAM and subsequent 2013 QRAM applications.

c) As per the Company's updated Gas Costs evidence filed at Exhibit D1, Tab 2, Schedule 1, page 9, paragraph 2 the Company is now forecasting the cost consequences of unutilized STFT capacity to be $2.8 million.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: Exhibit D1, Tab 2, Schedule 1, Page 7

Preamble: The Company had taken a one year assignment of TCPL-FT Empress to Iroquois capacity effective November 1, 2011 and for purposes of the 2013 forecast has assumed that it will contract for long haul TCPL – FT Empress to CDA in the amount of 25,000 Gj's per day effective November 1, 2012.

Please confirm the counter-party of this assignment is Union Gas, another rate-regulated utility.

RESPONSE

The counter-party of the assignment was not Union Gas.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: Exhibit D1, Tab 2, Schedule 1, Page 7

Preamble: The Company had taken a one year assignment of TCPL-FT Empress to Iroquois capacity effective November 1, 2011 and for purposes of the 2013 forecast has assumed that it will contract for long haul TCPL – FT Empress to CDA in the amount of 25,000 Gj's per day effective November 1, 2012.

Independent of the answer above [FRPO Interrogatory #2] on the counter-party of the assignment:

a. Please provide the annualized cost of this assignment to EGD.

b. For the winter of 2011/2, please provide the actual utilization on a monthly basis broken down by:

   i. Total GJ's delivered
   ii. Total GJ's assigned or optimized
   iii. Value of assignment (total and per GJ)
   iv. Value of optimization (total and per GJ)

RESPONSE

a) The counter-party to the assignment provided a discount to Enbridge Gas Distribution such that the annualized cost of the transport (TCPL-FT Empress to Iroquois) was less than the TCPL toll. The annual transportation cost for 26,956 Gj's/day of capacity is $19.0 million assuming no change in TCPL tolls between now and October 31, 2012, inclusive of the discount of $2.5 million.

b) See table provided on the following page.

Witnesses: J. Sarnovsky
D. Small

	November	December	January	February	March
Total GJ's Delivered	808,680	835,636	835,636	781,724	835,636
Total GJ's Assigned or Optimized	-	-	-	-	-
Value of Assignment (total and per Gj)	-	-	-	-	-
Value of Optimization (total and per Gj)	-	-	-	-	-

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 7-8

Preamble: Enbridge also held a storage entitlement with Union Gas Limited for 21,259,700 Gj broken down into three contracts with varied expiry dates. In its decision in the NGEIR proceeding, dated November 7, 2006, the Board ruled that these contracts should be priced at cost of service rates and that a phased in approach to market based storage was in the best interests of customers in Ontario. All three of these contracts have expired and effective April 1, 2010 all of the Company's contracted third party storage is at market based rates.

Please provide the annualized cost per GJ of the replacement contracts contained in 2013 rates.

a) For comparative purposes, please provide the annualized cost of the legacy contracts that expired to the amount of storage in three contracts referred to above.

b) Please provide whatever analysis EGD performed to determine the resulting cost and the level of contracting entered into at the time of contract expiry.

RESPONSE

The 2013 annualized cost of the Market Based Storage can be found at Exhibit D3, Tab 3, Schedule 2, Column 1, Item # 1.4. This amount is predicated on the assumption that the storage contract(s) that expire March 31, 2013 are deemed to be continued for the purposes of the 2013 gas costs forecast.

a) A comparison to the value of the old cost of service contracts would provide no value. The Board in the NGEIR decision (EB-2005-0551 pp. 64 and 65) recognized that there was a substantial difference between cost-based and market-based storage prices and found that in the public interest there would be a transition period to market-based pricing for its storage needs. The referred to section is included below:

Witnesses: J. Sarnovsky
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The Board finds that a transition framework is warranted in the case of Enbridge. Enbridge does have access to storage alternatives and does operate within the competitive storage market. However, the quantity of storage it acquires from Union is a substantial portion of its total requirement, and, given the uncertainty around storage price regulation at the time Enbridge entered into its current contracts, it may have had limited effective access to alternatives at that time.

Given the current substantial difference between cost-based and market-based storage prices, if the prices of the new contracts were included in Enbridge's rates, there would be an increase in Enbridge's total storage costs (although the majority of Enbridge's storage costs would still be based on the costs of Tecumseh). The Board must be concerned about the impact on consumers from refraining from rate regulation and balance that consideration with the objectives of facilitating storage development and the competitive market. With respect to storage development, in section 5.2.1 we concluded that re-pricing existing storage does not provide an incentive to develop new storage; the Board is similarly satisfied that retaining cost-based rates for existing storage for a transition period will not create an adverse impact on new storage development.

With respect to protecting consumers, the Board finds that it is in the public interest to provide Enbridge and its customers with a transition to market-based pricing for its storage needs (in excess of its Tecumseh capacity), rather than requiring it to access the competitive market for its full requirement all at one time. This will have the effect of phasing-in the rate impact on Enbridge's customers, and facilitating the development of competitive alternatives – to the benefit of Enbridge's customers and competitive storage providers. The Board finds that this transition should begin in 2008 and be completed in 2010. This timing will allow Enbridge to tender for services during 2007. Enbridge's rates in 2007 will continue to reflect cost-based storage rates for the services it acquires from Union.

The way to achieve this transition is for Union and Enbridge to amend the current contracts (which under section 4.04 would expire as of March 31, 2007 as a result of the Board's NGEIR decision) to maintain the current volumes and expiration dates but to replace the market-based rates with cost-based rates. The result of this approach would be that in 2008 Enbridge would need to acquire 9.4 Bcf (less than 10% of its storage requirement) from the competitive market. Smaller incremental amounts would be sourced from the competitive market in 2009 and 2010. The Board concludes that the phased approach, and the relatively small amounts of competitively sourced storage added each year, will result in a small net impact on Enbridge customer rates. In this way, the interests of consumers will be sufficiently protected.

b) In order to provide the analysis requested it would require a filing of all the bids that Enbridge received including all the particulars of the bids. In the interest of maintaining the integrity of the RFP process and to ensure that Enbridge will continue to receive qualitative bids, Enbridge considers it necessary to provide prospective bidders assurances that the particulars of their bid will not be disclosed to the public. Therefore, the Company is not prepared to file the information

Witnesses: J. Sarnovsky
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requested. However, Enbridge is prepared to file a description of the RFP process and the selection criteria for determining the successful bidder.

A typical Storage RFP will be sent to a broad range of counter parties that Enbridge generally does business with. For example, when the Company sent out an RFP in May of 2011 a total of 13 responses were received with a total of 38 storage offerings. In the RFP Enbridge identifies the effective date, term and maximum balance that is being requested as well as the location. The location will identify Enbridge's preference to deliver to Union Dawn for injection and to accept re-delivery from the storage provider at Union Dawn for withdrawal; however, alternate receipt and delivery points are considered. Also included in the RFP is the firm Injection/withdrawal schedule and the associated deliverability rights that Enbridge is requesting.

Responses to the RFP are sent back to Enbridge within seven to ten days and the bids are ranked in order by term and by total annual estimated cost (including commodity, transportation and fuel charges). The highest priced bids can be excluded right away, however, price is not always the determining factor. It is highly unlikely that two bids will be the exact same in size, term, location, firm injection/withdrawal rights (including deliverability) and operational flexibility i.e., the ability to nominate intra-day. Another factor for consideration is whether or not the prospective bid is underpinned by actual storage assets. While this is not necessarily a requirement, typically storage services that are not underpinned by physical assets tend to have less operational flexibility. Another concern is the credit worthiness of the counter-party. The Gas Supply group evaluates the various bids taking into account all of these considerations.

See response to CME Interrogatory #3 at Exhibit I, Issue D2, Schedule 4.3.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

Please provide the detailed analysis that supports the increase in STFT.

a. Please provide the specific level of demand that would be necessitated by the results of the Design Criteria Study.

b. Please provide the specific calculations and supporting assumptions that determined the "$66.2 or $74.5 million in total of unutilized transportation cost impacts."

c. Using April 2011 to March 2012 actual values, please provide monthly values for:

    i. The quantity of daily firm transport contracted in each TCPL delivery zone.
    ii. The quantity of daily firm transport delivered to other EGD delivery zones by other providers.
    iii. The quantity of daily firm TCPL contracts optimized to generate revenue versus recovered in EGD transportation rates?
    iv. The amount of FT-RAM credits accrued.
    v. The amount of revenue generated by utilization of those credits.
    vi. The demand charges for the transportation that was optimized.

d. Please clarify where the demand charge costs were charged and to what account were the revenues accrued.

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RESPONSE

a) The 2013 gas cost was prepared assuming, among other things, a peak day demand based upon the existing Design Day Demand Criteria of 39.5 degree days which equates to a peak day demand of 99 280 10^3m^3 (3.5 Bcf). If the Board were to accept the Company's proposal for a new Design Day Demand Criteria of 43.7 degree days this would equate to a peak day demand of 108 590 10^3m^3 (3.8 Bcf). See the response to Board Staff Interrogatory #13 at Exhibit I, Issue D3, Schedule 1.13.

b) The updated evidence identifies $2.8 million as the amount of the unutilized capacity cost (Exhibit D1, Tab 2, Schedule 1, page 9, para. 2) which is calculated by applying the TCPL-FT toll times the unutilized capacity of 1,350,000 Gj's. If the Board were to accept the Company's proposed changes to the Design Day Demand Criteria then the Company would be required to contract for additional transportation to meet the increase in Peak Day Demand. As discussed in its Gas Cost evidence not all of that incremental capacity would be utilized. That incremental unutilized capacity would increase by 31,375,000 Gj's or $66.2 million.

c) The Company will re-iterate how capacity assignments and FT RAM credits contribute to Transactional Services revenue. While transactional service deals pertaining to transportation optimization utilize the utility transportation contracts, no deal will be entered into at the expense or risk of the customers of the utility. For example, during periods of reduced demand, typically during the summer months, Enbridge may optimize underutilized transportation capacity by executing basic exchanges between two points for a fee charged to a third party (i.e., Enbridge could move gas received at Dawn and redeliver to the CDA). During these same periods of reduced demand the Company may, temporarily release parts of its long haul TCPL capacity to third parties. Tied to each release is an exchange through which Enbridge generally delivers gas at Empress and receives an equivalent volume of gas at Dawn. The credit received from TCPL through the temporary assignment offset by the cost payable to the third party for the transportation capacity represents Transportation Optimization for Transactional Services purposes.

   As for FT RAM these credits are only accumulated if a shipper does not utilize 100% of its RAM eligible capacity (i.e., FT or STS). In the case of Enbridge this is generated only when the Company does not fully utilize its STS capacity. For example, if in the month of December Enbridge did not fully utilize its STS capacity then we would have available credits that can be applied against the costs associated with any IT transportation costs that might be incurred by the Company in

Witnesses: J. Sarnovsky
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the month of December. However if Enbridge does not contract for any IT transportation service in that month then any STS-RAM credits go unutilized as credits cannot be carried forward to a subsequent month. To the extent that the Company required IT transportation for the purposes of meeting the needs of the Utility then any STS-RAM credits received by the Company would go toward lowering the transportation costs to the benefit of the rate payer and be captured as part of the PGVA. If however, the Utility did not require any IT transportation and there was an opportunity to enter into a Transactional Services deal with a third party through the use of IT transportation then any STS-RAM credits received would offset that IT transportation cost and provide a benefit as part of the Transactional Services Transportation Optimization.

The attached table provides the daily contracted demand level of the contracts in place for the months April 2011 to March 2012. Item # 1 represents the contracted TCPL FT capacity from Empress to the CDA. Item # 2 represents the amount of CDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 3 represents the contracted TCPL FT capacity from Empress to the EDA and Item # 4 represents the amount of EDA capacity that has been assigned to Ontario T-Service customers as of the 1st of each month. Item # 5 represents the amount of Empress to EDA capacity that has been released to a third-party (for purposes of this schedule only those capacity assignments that were for an entire month, were included). This is a Transactional Services arrangement that is referred to as an Empress to Dawn Exchange. Enbridge will purchase gas at Empress and as part of the exchange with the counterparty will return the gas to Enbridge at Dawn on the same day. As part of this exchange deal the Company will assign to the counterparty long-haul TCPL capacity. Enbridge will receive a credit from TCPL for the amount of the assignment which is greater than the amount being paid to the counterparty to move the gas to Dawn. For gas costs purposes the assignment is deemed to not have happened i.e., the demand charge cost and commodity cost are included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid for transport to the counterparty is recorded as Transactional Services revenue and recorded as Transportation Optimization. Item # 6 represents the one year assignment of Empress to Iroquois capacity that was mentioned as part of the Gas Supply evidence. Item #'s 7 and 8 represent the Contracted STFT amounts. Item # 9 is the level of Enbridges' contracted TCPL Dawn to CDA capacity and Item # 10 represents the amount of that capacity that has been assigned to ABM's as a part of the System Reliability proceeding. Item # 11 is the level of Enbridges' contracted TCPL Dawn to EDA capacity. Item # 12 represents the amount of the Dawn to EDA capacity that was assigned to third parties (for purposes

of this schedule only those capacity assignments that were for an entire month were included) as part of a Transactional Services deal. Similar to Item # 5 for purposes of gas costs the assignment is deemed to not have happened i.e., the demand charge cost is included as purchase costs, thereby having no impact on the PGVA. The benefit, which is the difference between the credit received from TCPL and the amount paid to the counterparty is recorded as Transactional Services revenue Transportation Optimization. Item #'s 13 to 16 are the remaining transportation arrangements Enbridge has with TCPL. Item #'s 17 and 18 represent the transportation commitments the Company has with Union Gas. Item #'s 19 to 21 represent the revenue and costs associated with the release of capacity to third parties as discussed above. Item #'s 22 to 24 provide the monthly TCPL IT transportation costs and STS RAM credits incurred by the Company. These costs are further broken down between costs incurred for Utility purposes or for purposes of generating Transactional Services revenue – Item #'s 25 & 26. Item # 27 provides the Transactional Services revenue attributable to that transaction and Item # 28 provides the net revenue.

d) See response to part c)

Witnesses: J. Sarnovsky
D. Small

Item #	Transportation	Route	Contracted Daily Volume	Column 1 Apr-11	Column 2 May-11	Column 3 Jun-11	Column 4 Jul-11	Column 5 Aug-11	Column 6 Sep-11	Column 7 Oct-11	Column 8 Nov-11	Column 9 Dec-11	Column 10 Jan-12	Column 11 Feb-12	Column 12 Mar-12
	GJ's														
1	TCPL FT - CDA	Empress to CDA		63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468	63,468
2	Direct Purchase Assignment	Empress to CDA		(7,732)	(7,772)	(7,772)	(7,784)	(7,757)	(7,762)	(7,733)	(7,388)	(7,387)	(7,317)	(7,371)	(7,387)
3	TCPL FT - EDA	Empress to EDA		196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970	196,970
4	Direct Purchase Assignment	Empress to EDA		(15,391)	(15,299)	(15,189)	(14,952)	(14,790)	(14,530)	(14,336)	(14,621)	(12,880)	(13,065)	(12,420)	(11,439)
5	Transactional Services Capacity Release	Empress to EDA		(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	(41,088)	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois		-	-	-	-	-	-	-	26,956	26,956	26,956	26,956	26,956
7	TCPL STFT - CDA	Empress to CDA		-	-	-	-	-	-	-	50,000	175,000	250,000	250,000	125,000
8	TCPL STFT - EDA	Empress to EDA		-	-	-	-	-	-	-	-	50,000	75,000	75,000	25,000
9	TCPL FT Dawn to CDA			149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
10	Direct Purchase Assignment as per System Reliability			(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)	(44,533)	(44,533)	(44,533)	(44,533)	(44,533)
11	TCPL FT Dawn to EDA			114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
12	Tranasactional Services Assignment			(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	-	-	-	-	-
13	TCPL FT Dawn to Iroquois			40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000	40,000
14	TCPL FT-SN Parkway to CDA			85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
15	TCPL STS Parkway to CDA			284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
16	TCPL STS Parkway to EDA			80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
17	Union Gas Dawn to Parkway			2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
18	Union Gas Dawn to Kirkwall			67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000's)														
19	Transactional Services Revenue - credit received from TCPL			2,899.6	2,905.7	2,899.6	2,905.7	2,906.3	2,900.2	2,906.3	-	-	-	-	-
20	Transactional Services Expense - amount paid to counterparty			(2,413.7)	(2,494.2)	(2,413.7)	(2,494.2)	(2,494.2)	(2,413.7)	(2,494.2)	-	-	-	-	-
21	Transactional Services Net Revenue			485.8	411.5	485.8	411.5	412.1	486.4	412.1	-	-	-	-	-
22	TCPL IT costs - Before STS RAM Credits			338.7	172.7	91.5	177.6	236.5	148.3	55.8	647.3	651.4	402.4	586.7	424.0
23	TCPL STS RAM Credits			(316.5)	-	-	-	-	-	-	(608.8)	(612.8)	(375.9)	(540.7)	(398.9)
24	Net Cost			22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
25	Amount charged to Gas Cost			0.2	172.7	91.5	177.6	236.5	148.3	55.8	-	5.1	2.3	-	4.6
26	Amount charged as Transactional Services Expense			22.0	-	-	-	-	-	-	38.5	33.5	24.3	46.0	20.6
				22.2	172.7	91.5	177.6	236.5	148.3	55.8	38.5	38.6	26.6	46.0	25.2
27	Associated Transactional Services Revenue			106.7	-	-	-	-	-	-	367.8	265.0	294.3	332.2	269.6
28	Transactional Services Net Revenue			84.7	-	-	-	-	-	-	329.3	231.5	270.0	286.2	249.1

FRPO INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

For the above question [FRPO Interrogatory #5] please provide in tabular fashion answers to the above inquiries for the years starting in April 2008 to March 2009 and continuing to April 2009 to March 2011.

RESPONSE

The attached schedules provide similar information to that set out in the response to FRPO Interrogatory #5 at Issue I, Issue D2, Schedule 8.5.

Witnesses: J. Sarnovsky
D. Small

Item #	Transportation	Route	Contracted Daily Volume	Column 1 Apr-08	Column 2 May-08	Column 3 Jun-08	Column 4 Jul-08	Column 5 Aug-08	Column 6 Sep-08	Column 7 Oct-08	Column 8 Nov-08	Column 9 Dec-08	Column 10 Jan-09	Column 11 Feb-09	Column 12 Mar-09
	GJ's														
1	TCPL FT - CDA	Empress to CDA		62,200	62,200	62,200	62,200	62,200	62,200	62,200	55,093	55,093	55,093	55,093	55,093
2	Direct Purchase Assignment	Empress to CDA		(21,338)	(21,362)	(21,799)	(21,728)	(22,106)	(22,172)	(22,144)	(16,405)	(16,375)	(16,205)	(16,092)	(16,225)
3	TCPL FT - EDA	Empress to EDA		154,744	154,744	154,744	154,744	154,744	154,744	154,744	179,744	179,744	179,744	179,744	179,744
4	Direct Purchase Assignment	Empress to EDA		(37,051)	(37,159)	(37,125)	(36,640)	(35,114)	(34,955)	(36,865)	(33,131)	(32,509)	(32,258)	(32,266)	(31,475)
5	Transactional Services Capacity Release	Empress to EDA		-	-	-	-	-	-	-	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois		56,293	56,293	56,293	56,293	56,293	56,293	56,293	56,293	56,293	56,293	56,293	56,293
7	Tranasactional Services Capacity Release	Empress to Iroquois		-	-	-	-	-	-	-	-	-	-	-	-
8	TCPL STFT - CDA	Empress to CDA		-	-	-	-	-	-	-	-	-	-	-	-
9	TCPL STFT - EDA	Empress to EDA		-	-	-	-	-	-	-	-	-	-	-	-
10	TCPL FT Dawn to CDA			149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
11	Direct Purchase Assignment as per System Reliability			-	-	-	-	-	-	-	-	-	-	-	-
12	Tranasactional Services Assignment			(21,101)	(21,101)	(21,101)	(21,101)	(21,101)	(21,101)	(21,101)	-	-	-	-	-
13	TCPL FT Dawn to EDA			114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
14	Tranasactional Services Assignment			(10,551)	(10,551)	(10,551)	(10,551)	(10,551)	(10,551)	(10,551)	-	-	-	-	-
15	TCPL FT Dawn to Iroquois			-	-	-	-	-	-	-	-	-	-	-	-
16	TCPL FT-SN Parkway to CDA			85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
17	TCPL STS Parkway to CDA			283,892	283,892	283,892	283,892	283,892	283,892	283,892	284,464	284,464	284,464	284,464	284,464
18	TCPL STS Parkway to EDA			80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
19	Union Gas Dawn to Parkway			2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
20	Union Gas Dawn to Kirkwall			67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000')														
21	Transactional Services Revenue - credit from TCPL			203.5	192.2	214.4	206.7	206.7	206.7	206.7	-	-	-	-	-
22	Transactional Services Expense - amount payable to counterparty			(168.8)	(158.2)	(163.3)	(165.4)	(172.7)	(170.5)	(172.7)	-	-	-	-	-
23	Transactional Services Net Revenue			34.6	34.0	51.0	41.3	33.9	36.2	33.9	-	-	-	-	-
24	TCPL IT costs - Before STS RAM Credits			253.5	341.6	439.3	336.8	292.0	326.6	142.9	424.6	340.2	142.3	253.2	333.9
25	STS RAM Credits			(239.1)	-	-	-	-	-	-	(390.4)	(283.2)	(132.1)	(140.3)	(304.9)
26	Net Cost			14.4	341.6	439.3	336.8	292.0	326.6	142.9	34.2	57.0	10.3	112.9	29.0
27	Amount charged to Gas Cost			10.6	341.6	439.3	336.8	292.0	326.6	142.9	1.7	57.0	0.8	21.0	1.7
28	Amount charged as Transactional Services Expense			3.8	-	-	-	-	-	-	32.5	-	9.4	91.9	27.3
				14.4	341.6	439.3	336.8	292.0	326.6	142.9	34.2	57.0	10.3	112.9	29.0
29	Associated Transactional Services Revenue			36.8	-	-	-	-	-	-	238.9	-	44.4	146.2	288.2
30	Transactional Services Net Revenue			33.0	-	-	-	-	-	-	206.4	-	35.0	54.3	260.9

we did stft for the month in july and august

Item #	Transportation	Route	Contracted Daily Volume	75000 Enbridge cda to union cda									
			Column 1 Apr-09	Column 2 May-09	Column 3 Jun-09	Column 4 Jul-09	Column 5 Aug-09	Column 6 Sep-09	Column 7 Oct-09	Column 8 Nov-09	Column 9 Dec-09	Column 10 Jan-10	Column 11 Feb-10	Column 12 Mar-10
	GJ's													
1	TCPL FT - CDA	Empress to CDA	55,093	55,093	55,093	55,093	55,093	55,093	55,093	80,093	80,093	80,093	80,093	80,093
2	Direct Purchase Assignment	Empress to CDA	(16,225)	(16,207)	(16,015)	(15,853)	(15,813)	(15,810)	(15,838)	(14,930)	(14,920)	(14,848)	(14,834)	(14,811)
3	TCPL FT - EDA	Empress to EDA	154,744	154,744	154,744	154,744	154,744	154,744	154,744	211,037	211,037	211,037	211,037	211,037
4	Direct Purchase Assignment	Empress to EDA	(31,410)	(31,293)	(31,230)	(30,691)	(30,497)	(30,452)	(30,139)	(29,696)	(29,278)	(28,938)	(28,914)	(29,021)
5	Transactional Services Capacity Release	Empress to EDA	(9,951)	(25,473)	(25,473)	(25,473)	(25,473)	(25,473)	(25,473)	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois	56,293	56,293	56,293	56,293	56,293	56,293	56,293	-	-	-	-	-
7	Tranasactional Services Capacity Release	Empress to Iroquois	-	-	-	(21,101)	(21,101)	(21,101)	(21,101)					
8	TCPL STFT - CDA	Empress to CDA	-	-	-	-	-	-	-	-	-	50,000	50,000	-
9	TCPL STFT - EDA	Empress to EDA	-	-	-	-	-	-	-	-	-	25,000	25,000	-
10	TCPL FT Dawn to CDA		149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
11	Direct Purchase Assignment as per System Reliability		-	-	-	-	-	-	-	-	-	-	-	-
12	Tranasactional Services Assignment		(31,652)	(31,652)	(31,652)	(31,652)	(31,652)	(31,652)	(31,652)					
13	TCPL FT Dawn to EDA		114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
14	Tranasactional Services Assignment		-	-	-	-	(10,551)	-	-	(15,826)	-	-	-	-
15	TCPL FT Dawn to Iroquois		-	-	-	-	-	-	-	-	-	-	-	-
16	TCPL FT-SN Parkway to CDA		85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
17	TCPL STS Parkway to CDA		284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
18	TCPL STS Parkway to EDA		80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
19	Union Gas Dawn to Parkway		2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
20	Union Gas Dawn to Kirkwall		67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000')													
21	Transactional Services Revenue - credit from TCPL		816.8	976.3	976.3	976.3	1,147.4	1,073.7	976.3	129.4	-	-	-	-
22	Transactional Services Expense - amount payable to counterparty		(727.7)	(901.2)	(876.2)	(901.2)	(1,018.2)	(928.6)	(901.2)	(103.3)	-	-	-	-
23	Transactional Services Net Revenue		89.1	75.1	100.1	75.1	129.2	145.1	75.1	26.1	-	-	-	-
24	TCPL IT costs - Before STS RAM Credits		269.9	131.1	276.3	130.4	164.8	311.9	47.8	439.2	166.9	194.7	224.7	493.1
25	STS RAM Credits		(157.4)	-	-	-	-	-	-	(407.8)	(154.9)	(186.6)	(215.5)	(472.4)
26	Net Cost		112.5	131.1	276.3	130.4	164.8	311.9	47.8	31.4	12.0	8.1	9.1	20.7
27	Amount charged to Gas Cost		112.5	131.1	276.3	130.4	164.8	311.9	47.8	5.3	2.5	1.1	2.7	(0.0)
28	Amount charged as Transactional Services Expense		-	-	-	-	-	-	-	26.1	9.5	7.0	6.4	20.7
			112.5	131.1	276.3	130.4	164.8	311.9	47.8	31.4	12.0	8.1	9.1	20.7
29	Associated Transactional Services Revenue		-	-	-	-	-	-	-	97.3	100.2	55.3	37.9	215.7
30	Transactional Services Net Revenue		-	-	-	-	-	-	-	71.2	90.7	48.3	31.5	195.0

25000 stft for 7days in february - eda
20000 stft for 7days in march - eda

Item #	Transportation	Route	Daily Volume	Column 1 Apr-10	Column 2 May-10	Column 3 Jun-10	Column 4 Jul-10	Column 5 Aug-10	Column 6 Sep-10	Column 7 Oct-10	Column 8 Nov-10	Column 9 Dec-10	Column 10 Jan-11	Column 11 Feb-11	Column 12 Mar-11
	GJ's														
1	TCPL FT - CDA	Empress to CDA		80,093	80,093	80,093	80,093	80,093	80,093	80,093	63,468	63,468	63,468	63,468	63,468
2	Direct Purchase Assignment	Empress to CDA		(14,744)	(14,691)	(15,814)	(16,498)	(16,403)	(16,387)	(18,442)	(7,807)	(7,767)	(7,766)	(7,803)	(7,801)
3	TCPL FT - EDA	Empress to EDA		211,037	211,037	211,037	211,037	211,037	211,037	211,037	196,970	196,970	196,970	196,970	196,970
4	Direct Purchase Assignment	Empress to EDA		(28,606)	(28,352)	(28,830)	(28,462)	(28,133)	(27,960)	(28,364)	(17,749)	(17,286)	(16,366)	(15,978)	(15,561)
5	Transactional Services Capacity Release	Empress to EDA		(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	-	-	-	-	-
6	TCPL FT - Iroquois	Empress to Iroquois		-	-	-	-	-	-	-	-	-	-	-	-
7	Tranasactional Services Capacity Release	Empress to Iroquois													
8	TCPL STFT - CDA	Empress to CDA		-	-	-	-	-	-	-	50,000	200,000	200,000	200,000	100,000
9	TCPL STFT - EDA	Empress to EDA		-	-	-	-	-	-	-	-	50,000	50,000	50,000	-
10	TCPL FT Dawn to CDA			149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818	149,818
11	Direct Purchase Assignment as per System Reliability			-	-	-	-	-	-	-	(49,102)	(49,102)	(49,102)	(49,102)	(49,102)
12	Tranasactional Services Assignment			-	-	-	-	-	-	-	-	-	-	-	-
13	TCPL FT Dawn to EDA			114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000	114,000
14	Tranasactional Services Assignment			(6,076)	(9,918)	(12,668)	(23,487)	(24,250)	(5,317)	(9,159)	(10,627)	-	-	-	-
15	TCPL FT Dawn to Iroquois			-	-	-	-	-	40,000	40,000	40,000	40,000	40,000	40,000	40,000
16	TCPL FT-SN Parkway to CDA			85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000
17	TCPL STS Parkway to CDA			284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464	284,464
18	TCPL STS Parkway to EDA			80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611	80,611
19	Union Gas Dawn to Parkway			2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173	2,157,173
20	Union Gas Dawn to Kirkwall			67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929	67,929
	$ (000')														
21	Transactional Services Revenue - credit from TCPL			2,358.5	2,024.5	2,334.4	2,274.8	2,300.6	2,055.2	2,103.8	108.4	-	-	-	-
22	Transactional Services Expense - amount payable to counterparty			(2,235.2)	(1,960.5)	(1,927.0)	(2,111.9)	(2,075.4)	(1,847.6)	(1,952.0)	(103.6)	-	-	-	-
23	Transactional Services Net Revenue			123.3	64.0	407.4	162.8	225.2	207.6	151.8	4.8	-	-	-	-
24	TCPL IT costs - Before STS RAM Credits			272.7	173.4	151.6	112.6	173.4	222.1	4.5	431.0	217.2	171.3	169.7	470.7
25	STS RAM Credits			(250.1)	-	-	-	-	-	-	(414.3)	(208.8)	(164.8)	(163.1)	(442.8)
26	Net Cost			22.6	173.4	151.6	112.6	173.4	222.1	4.5	16.7	8.4	6.5	6.6	28.0
27	Amount charged to Gas Cost			7.9	173.4	151.6	112.6	173.4	222.1	4.5	(0.0)	0.0	4.8	0.0	-
28	Amount charged as Transactional Services Expense			14.7	-	-	-	-	-	-	16.7	8.4	1.7	6.6	28.0
				22.6	173.4	151.6	112.6	173.4	222.1	4.5	16.7	8.4	6.5	6.6	28.0
29	Associated Transactional Services Revenue			31.5	-	-	-	-	-	-	208.3	43.8	13.6	56.3	138.9
30	Transactional Services Net Revenue			16.8	-	-	-	-	-	-	191.6	35.4	11.8	49.7	110.9

FRPO INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

For each of the above years [as noted in FRPO Interrogatory #6] please provide on a per/GJ basis the results on any bid or inquiry that EGD performed to consider the cost of winter peaking service.

a. Please provide the number of days, location and physical quantity received by EGD upon inquiry of the service.
b. Using historical data from the last ten years, please provide the quantity of gas received in each respective years (April to March), the cost paid for the delivery service on a per GJ basis.
c. Please provide the value of that quantity of delivery service in each year if the deliveries were made via:

    i. Annual FT service
    ii. Seasonal STFT service (Jan.- Mar.)
    iii. Monthly STFT service (Jan.- Mar.)
    iv. Weekly STFT service (Jan.-Mar.)

Witnesses: J. Sarnovsky
D. Small

RESPONSE

The Company wishes to maintain the integrity of its RFP process and believes that bids received as part of an RFP process are commercially sensitive information and therefore, is not prepared to provide information with respect to bids received for peaking service for the 2008/09, 2009/10 or 2010/11 winter periods.

a) and b) The Company views a request for ten years of history regarding peaking service to be a time consuming exercise that would be of little additional value. The Company has however, provided below the actual peaking service received for winters 2008/09, 2009/10 and 2010/11 and the associated cost of that service.

	Gj's	$/Gj's
2008/09	1,496,069	10.108
2009/10	870,430	9.365
2010/11	1,200,990	7.058

c) As part of its gas supply portfolio Enbridge contracts for peaking supplies that are utilized in peak or near peak conditions. Peaking supplies are pre-contracted arrangements for delivered supply to Enbridge's franchise area that it can call upon, typically on at least 10 days during the winter season. Enbridge is not privy to the transportation arrangements that would underpin the Peaking Service contracts. Therefore, the Company cannot provide the information requested.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

Please describe EGD's utilization of the FT-RAM service provided by TCPL since 2008.

a. Using the years since 2008, for each year, please provide:

i. The amount of TCPL provided to each of the EGD TCPL delivery zones.
ii. The cost of that transport in demand charges to ratepayers.
iii. The amount of UDC incurred
iv. The dollar value charged in rates to ratepayers for UDC.
v. The amount of FT-RAM credits generated, by month, for each of these years.
vi. The amount of revenue generated by these credits
vii. Please describe the disposition of this revenue over the respective years.

RESPONSE

As mentioned in the response to FRPO Interrogatory #5 at Exhibit I, Issue D2, Schedule 8.5, Enbridge does not receive any FT RAM credits from long haul TCPL FT capacity. Enbridge does receive STS RAM credits which have been identified in tables to responses to FRPO Interrogatories #5 and 6 at Exhibit I, Issue D2, Schedules 8.5 and 8.6. The Company did not incur any UDC on its long haul TCPL FT capacity.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 1. Page 10

Preamble: In the original evidence the Company also identified that it would be bringing forward a new Design Criteria Study. The Company discussed that given the current transportation available that the only option would be to increase the level of TCPL longhaul STFT. Based on the demand forecast filed at that time, the impact on 2013 gas costs would be an incremental $66.2 million or $74.5 million in total of unutilized transportation costs impacts. Based on the updated volumetric forecast the total cost impact on 2013 gas costs would be $69.0 million.

Based upon EGD review of winter seasonal and peaking requirements in the last ten years:

a. Please provide the number of time that the peak day has occurred in November?

b. Please provide the number of time that the peak day has occurred in December?

c. Please provide the number of time that the peak day has occurred in March?

d. Please discuss the reasons behind EGD's strategy to purchase its System Reliability from November to March.

RESPONSE

a) In the last ten years peak day has never occurred in November.

b) In the last ten years, peak day has never occurred in December. However, in the last fifteen years, peak day has occurred in December once. In addition, given the relatively mild winter experienced in 2012 the Company believes there is a greater chance of 2012 peak day occurring in December of 2012.

Witnesses: J. Sarnovsky
D. Small

c) In the last ten years, peak day has never occurred in March.

d) The Company is unclear about the question being asked. There were two elements of the System Reliability proceeding pertaining to the acquisition of STFT. The first dealt with the one year assignment of 50,000 Gj/day of Enbridge's contracted TCPL Short Haul firm capacity from Dawn to the CDA. To replace that capacity the Company would contract for an equivalent volume of TCPL STFT from November to March. This was agreed to by the parties to the Settlement Agreement and was approved by the Board. Another element of the System Reliability proceeding was the issue raised by the Company for the need to replace traditional Peaking Supplies with TCPL STFT. Again, through the Consultative, parties agreed as part of the Settlement Agreement (which the Board accepted) that Enbridge would acquire a total of 200,000 Gj/day of STFT for three months during the winter season.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 2: Is Enbridge's gas supply plan, including the forecast of gas, transportation and storage costs appropriate?

Reference: D1, Tab 2, Schedule 2

Preamble: In lines 23-26, EGD states that the Vector contracts are a negotiated toll.

Please provide the resulting negotiated tolls for the contracts that have been extended or in the process of being committed to through a company process.

RESPONSE

Negotiated tolls are commercially sensitive information and while the Company is not willing to provide the negotiated toll, Enbridge can advise that it is lower than the recourse rate thereby providing a benefit to the rate payer.

Witnesses: J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D2 / Tab 4 /Sch 2 (Navigant Report)

Navigant concludes on page 7 of its report that, "The higher standard deviation implies that the risk of larger and more frequent extreme cold events is higher compared with the data set that underlies EGD's current design day." Board staff presumes that Navigant bases its conclusion on the values in the "Annual Peak HDD Normals" table that it provides at the reference. In this table the Standard Deviation for the period 1957-1993 is stated as 2.24, and as 3.86 for the period 1994 through 2009.

1957-1993 represents a period of 37 years, while 1994-2009 is 16 years.
1957-1983 represents a period of 27 years, while 1984-2009 is 26 years.

a) Has the resolution of temperature measuring equipment improved over the period from 1957 to 2009? If so, please comment on the potential that this may result in the observation of higher or lower observed temperatures, and any error this may introduce non-uniformly throughout the data.

b) Please provide a table of "Annual Peak HDD Normals" that uses the period 1957-1983 and 1984-2009. This provides two periods that are similar in duration (27 and 26 years).

   i. Please comment on the effect on the standard deviation of these two periods.

c) Based on the observations in part (b), please indicate whether Navigant Consulting wishes to adjust or withdraw its conclusion regarding higher standard deviation and more extreme cold weather events over the recent period.

d) It is difficult to determine the statistical significance of the difference between the reported averages and standard deviations in the Navigant Report. Please test the significance of the difference between the average over each period and standard

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

deviation over each period, as each is reported in Table 1, by calculating and providing the following:

i. The test statistic and p-value for a t-test of the null hypothesis that the mean Peak HDD from 1957 to 1993 is equal to the mean Peak HDD from 1994 to 2009; and
ii. The test statistic and p-value for a test of the null hypothesis that the standard deviation from 1957 to 1993 is equal to the standard deviation from 1994 to 2009.

In both cases clearly state any assumptions needed to calculate the statistics.

e) In Table 1 Navigant has claimed that the mean is lower in the more recent period as compared with the period from 1957-1993. In conjunction with Navigant's statement that "higher standard deviation implies that the risk of larger and more frequent extreme cold events is higher," please explain how a lower average peak temperature but a higher standard deviation implies that the risk of "larger" and "more frequent" extreme cold events is higher.

f) What region or regions does the data in Table 1: Comparison of Historic Temperatures include?

g) Regarding the HDD peaks for the three regions for which data was provided, please respond to the following:

i. In developing the proposed new Design Day Criteria, does Enbridge consider the likelihood of a HDD peak occurring in all regions simultaneously, or are the peak HDDs in each of these regions presumed to occur independently?
ii. Regardless of the previous answer, is it possible that the company or its customers would be exposed to additional risk if HDD peaks were to occur simultaneously (or near simultaneously) in all three regions?
iii. Are there any operational considerations or other constraints which make planning and designing for the possibility of simultaneous peaks in all three regions unnecessary?

h) Please complete the following table, using the same source data as that used to produce Table 1.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

h) Peak HDD[1] by Region	Central			Eastern			Niagara		
	1957 - 1993	1994-2009	1957-2009	1957 -1993	1994-2009	1957-2009	1957 -1993	1994-2009	1957-2009
Number of observations[2]:									
Minimum									
Average									
Maximum									
Standard Deviation									
Date of Coldest Day									
Date of Warmest Day									

i) Please complete the following table for all regions, using the same source data as that used to produce Table 1.

i) Peak HDD[3] All Regions	All Regions		
	1957 - 1993	1994-2009	1957-2009
Number of observations[4]			
Minimum			
Average			
Maximum			
Standard Deviation			
Date of Coldest Day			
Date of Warmest Day			

[1] Please use the same method to calculate "Peak HDD" as that used to compile the "Peak HDD Normals" statistics in Table 1.
[2] Please provide the number of HDD data points used to calculate the statistics in the table.
[3] Please use the same method to calculate "Peak HDD" as that used to compile the "Peak HDD Normals" statistics in Table 1.
[4] Please provide the number of HDD data points used to calculate the statistics in the table.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

(j) Please complete the following table for each region, using the same source data as that used to produce Table 1. Please use all the HDD data (that is, the HDD observations for every day in the sample, not only peak days) to calculate the statistics in this table.

j) Total HDD by Region	Central			Eastern			Niagra		
	1957 -1993	1994- 2009	1957- 2009	1957 -1993	1994- 2009	1957- 2009	1957 -1993	1994- 2009	1957- 2009
Number of observations[5]									
Minimum									
Average									
Maximum									
Standard Deviation									
Date of Coldest Day									
Date of Warmest Day									

(k) Please complete the following table for all regions, using the same source data as that used to produce Table 1. Please use all the HDD data (that is, the HDD observations for every day in the sample, not only peak days) to calculate the statistics in this table.

[5] Please provide the number of HDD data points used to calculate the statistics in the table.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

k) Total HDD all Regions	All Regions 1957 -1993	1994-2009	1957-2009
Number of observations[6]			
Minimum			
Average			
Maximum			
Standard Deviation			
Date of Coldest Day			
Date of Warmest Day			

RESPONSE

a) Navigant Consulting has not examined or studied whether or not the resolution of temperature measuring equipment has improved over the time period identified or for that matter over any time period. Navigant Consulting therefore cannot provide any comments on the resolution of temperature measuring equipment.

b) The table on the following page has summary statistics for Annual Peak HDDs in the Central weather zone for the two time periods; 1957 to 1983 and from 1984 to 2009.

[6] Please provide the number of HDD data points used to calculate the statistics in the table.

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Annual Peak Heating Degree Days		
	Central	
Heating Degree Days	1957 through 1983	1984 through 2009
Period (Years)/ Number of Observations	27	26
Minimum	34.35	29.26
Mean	37.83	35.56
Maximum	42.76	44.07
Standard Deviation	2.30	3.18
Date of Coldest Day	3-Jan-81	15-Jan-94
Date of Warmest Day	9-Jan-78	30-Dec-98

i. The Standard Deviation of the Annual Peak HDDs for the period 1957 to 1983 is 2.30, and for the period 1984 to 2009 is 3.18. The Standard Deviation of the second period is higher than the first period.

c) Navigant wishes to clarify its conclusion regarding higher standard deviation and more extreme cold weather events over the recent period. The higher standard deviation implies that the risk of larger and more frequent extreme cold events is higher, relative to the more recent period's mean.

Based on the observations in the response to b) above, Navigant does not wish to adjust or withdraw its conclusion regarding higher standard deviation based on the two periods analyzed. For the two periods analyzed in part b) the standard deviation in the second period is greater than the standard deviation in the first period.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

d)

i. Test of the hypothesis that for the Central weather zone:

Mean(Peak HDD, 1957 through 1993) = Mean(Peak HDD, 1994 through 2009)

Calculate the t-statistic:

$$t = \frac{(x_1 - x_2)}{\sqrt{\frac{s_1^2}{n_1} + \frac{s_2^2}{n_2}}}$$

Where:

x_1 =	Mean (Peak HDD, 1957 through 1993)
x_2 =	Mean (Peak HDD, 1994 through 2009)
s_1 =	standard deviation (Peak HDD, 1957 through 1993)
s_2 =	standard deviation (Peak HDD, 1994 through 2009)
n_1 =	sample size (Peak HDD, 1957 through 1993)
n_2 =	sample size (Peak HDD, 1994 through 2009)

All of the values cited above are drawn from Table 1 of the Navigant report.

In this case:

$$t = 4.02$$

Since EGD believes that the sample standard deviation is different in the two samples, the Company must calculate the degrees of freedom (Df) using the following equation[7]:

$$Df = \frac{\left(\frac{s_1^2}{n_1} + \frac{s_2^2}{n_2}\right)^2}{\frac{\left(\frac{s_1^2}{n_1}\right)^2}{n_1 - 1} + \frac{\left(\frac{s_2^2}{n_2}\right)^2}{n_2 - 1}}$$

All the parameters are defined as above, and drawn from Table 1 of the report.

[7] National Institute of Standards and Technology, *Engineering Statistics Handbook*, April 2012 http://www.itl.nist.gov/div898/handbook/eda/section3/eda353.htm

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In this case:

$$Df = 22.88$$

The table below identifies the critical values for a two-sided test for various degrees of freedom at three levels of significance.

	Critical value of t-distribution (by Level of Significance)		
Df	10%	5%	1%
22	1.717	2.074	2.819
25	1.708	2.060	2.787
30	1.697	2.042	2.750

Thus the hypothesis that the two means are equal may be rejected at all conventional levels of confidence[8]; the difference between the means is statistically significant.

Using an on-line p-value calculator[9], the two-tailed p-value is: 0.0006.

The same tests were conducted for the Eastern and Niagara[10] regions. The mean, standard deviation, and sample values can be found in response h) below.

For all three regions, the table below summarizes the test statistic, p-value and whether the hypothesis that the means from the two different time periods are equal can be rejected or not.

[8] Degrees of freedom rounded down to nearest integer (for conservatism).
[9] http://graphpad.com/quickcalcs/PValue1.cfm
[10] The hypothesis for the Niagara region uses 1972 to 1993 for x1.

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					Reject Null Hypothesis? (by Level of Significance)		
Region	Null Hypothesis	t-stat	Df	p-value	10%	5%	1%
Central	mean ('57to'93) = mean('94to'09)	4.02	22	0.0006	Reject	Reject	Reject
Eastern	mean ('57to'93) = mean('94to'09)	3.22	25	0.0035	Reject	Reject	Reject
Niagara	mean ('72to'93) = mean('94to'09)	2.38	30	0.0239	Reject	Reject	Not Reject

The hypothesis that the means are equal can be rejected for the Central and Eastern region at all conventional levels of significance; the difference between the means is statistically significant. For the Niagara region the hypothesis that the means are equal can be rejected at all but the 1% level of significance.

ii. Test of the hypothesis that

Standard Deviation (Peak HDD, 1957 through 1993)
=
Standard Deviation (Peak HDD, 1994 through 2009)

This hypothesis is tested using the F-statistic, which is calculated as[11]:

$$F = \frac{s_1^2}{s_2^2}$$

[11] National Institute of Standards and Technology, *Engineering Statistics Handbook*, April 2012 http://www.itl.nist.gov/div898/handbook/eda/section3/eda359.htm

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All the parameters are defined as above, and drawn from Table 1 of the report. In this case:

$$F = 0.34$$

Numerator degrees of freedom = 36

Denominator degrees of freedom = 15

The hypothesis that the two variances (and thus, standard deviations) are equal is rejected if the test statistic is greater than the upper-tail critical value OR the test statistic is less than the lower-tail critical value.

Thus if:

$$F > F_{(\frac{\alpha}{2},n_1-1,n_2-1)}$$

OR

$$F < F_{\left(1-\frac{\alpha}{2},n_1-1,n_2-1\right)}$$

Where:

α = Defines the significance level

And[12]:

$$F_{(1-\frac{\alpha}{2},n_1-1,n_2-1)} = \frac{1}{F_{(\frac{\alpha}{2},n_1-1,n_2-1)}}$$

Critical values for the upper tail may be found in most post-secondary level statistics or econometrics textbooks, although interpolation would be required for the degrees of freedom in this case, and most only list tables with alpha values of 0.05 or 0.01 for

[12] Kenekl, James L. *Introductory Statistics for Management and Economics, Fourth Edition,* Duxbury Press, 1996, page 498

a single-tailed test (equivalent 0.1 and 0.02 for a two-tailed test). Therefore the upper tail critical value for a 95% significance level was generated using an on-line critical value calculator[13]:

$$F_{(\frac{0.05}{2},37-1,16-1)} = 2.6$$

And:

$$F_{(1-\frac{0.05}{2},37-1,15-1)} = \frac{1}{F_{(\frac{0.05}{2},37-1,16-1)}} = 0.38$$

Since the test statistic is less than the lower tail critical value, the hypothesis that the two variances are equal may be rejected at the 95% (or 0.05) level of significance, indicating that at this level of significance the difference between the two standard deviations is statistically significant.

Navigant notes that at the 99% (or 0.01) level of significance the hypothesis *cannot* be rejected, indicating that at that level of significance the difference between the two standard deviations is *not* statistically significant.

Navigant believes that the results above indicate that while it is highly probable that there truly is a difference between the standard deviations in the two periods examined there is a small, but non-trivial, probability that in fact the observed difference is just due to the inherent volatility of data-generating process.

The same tests were conducted for the Eastern and Niagara[14] regions. The mean, standard deviation, and sample values can be found in response h) below.

[13] AusVet Animal Health Services, *Epitools Epidemiological Calculators: P- and Critical Values for the F Distribution*, Accessed July 9, 2012
http://epitools.ausvet.com.au/content.php?page=f_dist
[14] The hypothesis for the Niagara region uses 1972 to 1993 for the first standard deviation period.

For all three regions, the table below summarizes the test statistic, p-value and whether the hypothesis that the standard deviation from the two different time periods are equal can be rejected or not.

					Reject by F-statistic Critical Value? (by Level of Significance)		
Region	Null Hypothesis	F-stat	Num. Df	Den. Df	10%	5%	1%
Central	stdev ('57to'93) = stdev ('94to'09)	0.34	36	15	Reject	Reject	Not Reject
Eastern	stdev ('57to'93) = stdev ('94to'09)	0.58	36	15	Not Reject	Not Reject	Not Reject
Niagara	stdev ('72to'93) = stdev ('94to'09)	0.72	21	15	Not Reject	Not Reject	Not Reject

For Eastern and Niagara regions at all levels of significance, the null hypothesis *cannot* be rejected, indicating that at the difference between the two standard deviations is *not* statistically significant.

The table on the following page summarizes the lower tail and upper tail critical values that were used to determine whether the null hypothesis could be rejected or not.

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			Lower Tail Critical Value (by Level of Significance)			Upper Tail Critical Value (by Level of Significance)		
Region	Num. Df	Den. Df	10%	5%	1%	10%	5%	1%
Central	36	15	0.45	0.38	0.28	2.22	2.60	3.62
Eastern	36	15	0.45	0.38	0.28	2.22	2.60	3.62
Niagara	21	15	0.43	0.36	0.26	2.32	2.74	3.86

e) See response c) above. The higher standard deviation suggests/implies that fluctuations of HDD around the average peak HDD of the second period will be more extreme than the fluctuations of HDD around the average peak HDD of the first period.

f) Table 1: Comparison of Historic Temperatures includes data for the Enbridge Central weather zone only.

g) Regarding the HDD peak values for the three regions in the Enbridge franchise area:

i. For gas supply planning purposes Enbridge assumes that peak day HDDs and therefore design conditions occur on the same day for all three weather zones.

ii. If Enbridge did not plan for simultaneous occurrence of peak day HDDs and thus design conditions across all three weather zones, Enbridge and its customers would be subject to more risk relative to a supply plan which does assume simultaneous occurrence of design conditions. As outlined in Enbridge's evidence at Exhibit D1, Tab 2, Schedule 3, page 2, designing a supply plan to meet winter demands, including the crucial peak day or day of highest demand is extremely important.

Assuming non-coincidence of design conditions could potentially result in Enbridge not having supplies sufficient to meet design conditions should actual peak day demand approach or equal design conditions and occur

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simultaneously across all three weather zones.

If actual HDD peaks were to occur simultaneously (or near simultaneously) in all three weather zones such that demand was near or exceeded design conditions (irrespective of whether or not Enbridge planned for simultaneous occurrence), Enbridge and its customers would be subject to more risk relative to a situation where peak day demand did not approach design conditions.

This increase in risk is due to the amount of unsecured supplies within the 2013 gas supply plan. Unsecured supplies include curtailment, peaking and direct purchase supplies. Unsecured supplies are supplies for which the Company does not know the transportation service attributes (for example firm transportation or interruptible transportation) used to transport gas to the franchise area or for which there is no guarantee that supplies will be available to meet demand (for example, curtailment).

For the 2013 gas supply plan absent the requested change in Design Criteria, unsecured supplies comprise approximately 19% of total supplies on peak day. Therefore only 81% of demand on peak day is met by secured supplies.

In the CDA secured supplies correspond to demand associated with approximately 31 HDDs whereas in the EDA secured supplies correspond to demand associated with approximately 34 HDDs. In the CDA the probability of 31 HDDs being met or exceeded in any given year is approximately 97% based on a normal distribution. Likewise for the EDA the probability of 34 HDDs being met or exceeded in any given year is approximately 99% based on a normal distribution. Consequently in any given year, peak day demands will have to be met utilizing unsecured supplies.

To the extent that demand reaches a level where unsecured supplies are relied upon to a greater extent the greater the risk that a certain portion of demand will not be met by supply.

iii. Not at this time. Due to the temperature sensitive nature of Enbridge's customer base, demand is high in the winter and low in the summer. Peak day demand has historically occurred in January or February of each year and typically peak day demand occurs simultaneously across all three weather zones. Assuming simultaneous design conditions is consistent with these observations.

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Hypothetically however, if, for whatever reason, peak day demand for any of the three weather zones were to shift to, for example, sometime in July or August it would make sense for Enbridge to assume different dates for design condition occurrence. Such a situation could occur, if for example, a significant amount of electricity generation was brought on line in Niagara and these generators chose to be supplied by Enbridge.

h) The following table was completed using the same source data as that used to produce Table 1 of the Navigant report. The same method was used to calculate "Peak HDD" as that used to compile the "Peak HDD Normals" statistics in Table 1 of the Navigant report.

Annual Peak Heating Degree Days									
	Central			Eastern			Niagara[15]		
Heating Degree Days	1957 through 1993	1994 through 2009	1957 through 2009	1957 through 1993	1994 through 2009	1957 through 2009	1972 through 1993	1994 through 2009	1972 through 2009
Period (Years)/Number of Observations	37	16	53	37	16	53	22	16	38
Minimum	34.21	29.26	29.26	37.95	33.08	33.08	30.06	28.65	28.65
Average	37.38	35.17	36.71	42.52	40.72	41.98	34.43	33.10	33.87
Maximum	42.76	44.07	44.07	49.55	48.18	49.55	40.32	38.52	40.32
Standard Deviation	2.24	3.86	2.97	2.86	3.77	3.23	2.59	3.06	2.83
Date of Coldest Day	3-Jan-81	15-Jan-94	15-Jan-94	3-Jan-81	15-Jan-94	3-Jan-81	3-Jan-81	18-Jan-94	3-Jan-81
Date of Warmest Day	15-Feb-91	30-Dec-98	30-Dec-98	25-Feb-90	3-Dec-02	3-Dec-02	21-Dec-75	1-Jan-01	1-Jan-01

[15] Data for the Niagara region only begins in June 1971. Calculations were done starting at first year with full data, 1972.

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i) Navigant Consulting and Enbridge interpret this interrogatory to request data pertaining to a single system wide peak day HDD value for each year within the samples identified. A response cannot be provided as the single system wide data requested are not calculated or tracked by Enbridge.

j) The following table uses the same source data as that used to produce Table 1 in the Navigant report. All the HDD data (that is, the HDD observations for every day in the sample, not only peak days) was used to calculate the statistics in this table.

Total HDD by Region									
	Central			Eastern			Niagara[16]		
Heating Degree Days	1957 through 1993	1994 through 2009	1957 through 2009	1957 through 1993	1994 through 2009	1957 through 2009	1972 through 1993	1994 through 2009	1972 through 2009
Number of Observations	13514	5844	19358	13514	5844	19358	8036	5844	13880
Minimum	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Average	11.43	10.41	11.12	12.87	12.25	12.68	10.48	10.02	10.29
Maximum	42.76	44.07	44.07	49.55	48.18	49.55	40.32	38.52	40.32
Standard Deviation	9.49	9.20	9.41	11.09	10.77	11.00	8.89	8.87	8.88
Date of Coldest Day	3-Jan-81	15-Jan-94	15-Jan-94	3-Jan-81	15-Jan-94	3-Jan-81	3-Jan-81	18-Jan-94	3-Jan-81
Date of Warmest Day[17]	Many	Many	Many	Many	Many	Many	Many	Many	Many

k) Navigant Consulting and Enbridge interpret this interrogatory to request data pertaining to a single system wide HDD value for each day of each year within the samples identified. A response cannot be provided as the single system wide data requested are not calculated or tracked by Enbridge.

[16] Data for the Niagara region only begins in June 1971. Calculations were done starting at first year with full data, 1972.
[17] If the average daily temperature is greater than or equal to 18 degree Celcius, the HDD for that day is 0. There are many days throughout the year with a HDD of 0.

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BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D2 / Tab 4 / Sch 2 (Navigant Report)

At page 7 of the Navigant report, Navigant states: "We used a standard form of autoregressive equation, shown below."

At Page 8 of the Navigant Report, Navigant states: "All of the residuals from each of the 365 days of the year were then used to estimate a probability distribution of the random weather variation which might occur on that day of the year."

a) What types of meteorological, statistical, or other regression models did Navigant consider when developing the HDD regression model before choosing the autoregressive (AR) specification to model HDDs?

b) Please describe which observations were included in the data set used to estimate the AR model. Confirm that all 365 days of each year were used to estimate the model. Please specify which years were used in the estimation, and state how many data points were used in total to estimate the model.

c) Please confirm that, in general, an autoregressive regression model is statistically valid only if the data used to estimate it is stationary.

    i. Please provide the results of *Dickey Fuller* and *Phillips Perron* tests for stationarity of the HDD data used to estimate the AR model. State the assumptions required to conduct each test.
    ii. What conclusions about the stationarity of the data used in the Navigant study would Enbridge and/or Navigant draw from the stationarity tests performed above?

d) Please explain how seasonal variation is accounted for in the AR model. Did Navigant estimate other specifications that would account for seasonality, and were

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these models rejected? Did Navigant test any models which included an interaction between HDD and either the monthly dummy variable or any other seasonal variables?

e) Please report the coefficients of the AR model estimated by Navigant.

f) Please report the statistics for the likelihood ratio, Lagrange Multiplier, and Wald tests of significance for the coefficients in the AR model. Please report, for each test, the test statistics and p-values for the hypothesis that each of the coefficients in the model are individually zero.

g) Does Navigant agree with the following interpretation of the coefficient on HDD_{t-1}: 'beta one captures the fraction of variation in HDD today that can be explained by the HDD yesterday'?

   i. If Navigant agrees with the statement directly above please explain how the coefficient in this model accounts for seasonal changes in temperature over the course of the year.
   ii. If Navigant disagrees with the statement, please provide an interpretation for the coefficient on HDD_{t-l} in the AR model.
   iii. Please explain how the specification of the AR model accounts for the seasonal fall in temperatures from early winter to mid-winter, and the seasonal increase in temperatures from mid-winter to early spring.
   iv. Does the specification of the AR model imply that the relationship between the temperature on any given day and the temperature on the following day is *constant* over the course of the period? By way of example, does the AR model imply that the relationship between the temperature on November 1 and the temperature on November 2 *is the same* as the relationship between the temperature on January 1 and the temperature on January 2, which is in turn the *same* as the relationship between the temperature on March 29 and the temperature on March 30, subject to the random variation in the error term and adjusted by the coefficient on the monthly dummy variables?

RESPONSE

a) Navigant considered only a few relatively simple regression model specifications before choosing the AR model used. The purpose of the regression model is only to provide a parsimonious and reasonably accurate model from which to develop the

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Monte Carlo analysis. Navigant anticipated that the individual daily estimated distributions that drive the Monte Carlo would compensate for any imprecision resulting from the selection of the (relatively simple) AR model used. That this is in fact the case may be seen in the consistency with which the mean Monte Carlo tracks the mean actual in Figure 2-C of the report. Further discussion of additional specifications tested may be found in response d) below and in Exhibit I, Issue D3, Schedule 1.3 response b).

b) For each region, Central, Eastern, and Niagara all 365 days of each year were used to estimate the model. The table below summarizes the number of observations and time period used to estimate the model for each region.

Region	Observations	Time Period
Central	21,078	Jan 1, 1953 – Sep 16, 2010
Eastern	21,077	Jan 1, 1953 – Sep 15, 2010
Niagara	14,329	Jun 23, 1971 – Sep 14, 2010

c) Navigant would agree that, in general, an autoregressive regression model based on stationary data will be more accurate than one based on non-stationary data.

i. Tests for stationarity.

The Dickey-Fuller test tests for stationarity by estimating the three models shown below in Table 1.

Table 1: Dickey-Fuller Test Model Specifications

Model	Description	Specification
A	Random walk	$\Delta y_t = \gamma y_{t-1} + \varepsilon_t$
B	Random walk with drift	$\Delta y_t = \alpha_0 + \gamma y_{t-1} + \varepsilon_t$
C	Random walk with drift and trend	$\Delta y_t = \alpha_0 + \gamma y_{t-1} + \alpha_1 t + \varepsilon_t$

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Where:

y_t = The heating degree days on day *t*.

t = A linear trend.

To test for a unit root:

H_0: $\gamma = 0$, there is a unit root.

H_1: $\gamma \neq 0$, there is no unit root.

Drift and trend are tested for using an analogous null and alternative hypothesis on the estimated coefficients α_0 and α_1.

Hypotheses are tested using τ (tau) statistic, which is calculated in the same manner as the t-statistic but is differently distributed, with the distribution changing depending upon which of the three model specifications is estimated. The critical values that must be used are shown in Table 2 below[1].

Table 2: Dickey-Fuller Test Critical Values

		Critical Value (by Level of Significance)		
Model	Hypothesis	10%	5%	1%
A	$\gamma = 0$	-1.61	-1.95	-2.6
B	$\gamma = 0$	-2.58	-2.89	-3.51
B	$\alpha_0 = 0$	2.17	2.54	3.22
C	$\gamma = 0$	-3.15	-3.45	-4.04
C	$\alpha_0 = 0$	2.73	3.11	3.78
C	$\alpha_1 = 0$	2.38	2.79	3.53

[1] Floyd, J., *Statistical Tables*, http://www.economics.utoronto.ca/jfloyd/book/statabs.pdf

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The tau statistics are all reported in Table 3, below.

Table 3: Tau Statistics for Dickey-Fuller Test

Model	Parameter	Central Region	Eastern Region	Niagara Region
A	γ	-16.99	-16.14	-14.9
B	γ	-26.49	-24.77	-22.93
B	α_0	20.19	18.67	17.3
C	γ	-26.53	-24.78	-22.95
C	α_0	14.17	12.76	11.92
C	α_1	-1.31	-0.75	-0.85

Assessing these estimates against the critical values in Table 2, we may reject the hypothesis of a unit root and we may reject the hypothesis of a zero mean. For all regions we cannot reject the hypothesis that $\alpha_1 = 0$, that is, we cannot reject the hypothesis that no trend exists in the daily HDD data. This implies the data is stationary.

The estimates above were obtained using the SAS PROC REG procedure and confirmed using the PROC ARIMA procedure. Tau statistics obtained on γ obtained using PROC ARIMA were trivially different (about 0.01 less for Central in all three models, 0.05 less for Eastern in all three models, and 0.01 more for Niagara model B and identical for Niagara models A and C) from those obtained using PROC REG.

Phillips-Perron tau test statistics were obtained using the PROC ARIMA procedure and were identical to the tau test statistics obtained using the Dickey-Fuller option of the PROC ARIMA procedure.

ii. The HDD data appears to be stationary in all three regions.

d) Seasonal variation is accounted for by the seasonal dummies included in the AR model. Seasonal variation not captured by these dummies is more precisely accounted for by the day-specific distributions estimated for the Monte Carlo analysis (see Exhibit I, Issue D3, Schedule 1.4, response d). Navigant did experiment with some other model specifications including one that included a

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seasonal (winter) dummy interacted with lagged HDD and one that interacted the lagged HDD with the monthly dummies. Such models were rejected in favour of the one used either for reasons of parsimony (using the Schwarz-Bayesian Criterion) or because including the additional interactions resulted in a very high level of residual serial correlation.

e) The table below reports the coefficients and adjusted R square of the AR models estimated by Navigant for each of the three regions.

Variable	Central	Eastern	Niagara
Adjusted R square	0.89	0.90	0.88
Intercept	6.561	7.688	6.301
HDD_{t-1}	0.687	0.696	0.674
Jan Dummy	0.962	0.976	0.930
Feb Dummy	0.562	0.250	0.677
Mar Dummy	-0.977	-1.689	-0.866
Apr Dummy	-3.114	-4.203	-2.866
May Dummy	-4.847	-6.114	-4.652
Jun Dummy	-5.999	-7.152	-5.810
Jul Dummy	-6.330	-7.475	-6.131
Aug Dummy	-6.212	-7.271	-6.011
Sep Dummy	-5.363	-6.256	-5.247
Oct Dummy	-3.702	-4.516	-3.554
Nov Dummy	-1.843	-2.430	-1.786

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f) Wald, likelihood ratio, and Lagrange Multiplier (LM) tests below.

Table 4: Central Region Test Statistics

	Likelihood Ratio		Wald		LM	
	Chi-Square	Pr > ChiSq	Chi-Square	Pr > ChiSq	Chi-Square	Pr > ChiSq
Intercept	2530.43	<.0001	2688.57	<.0001	3081.8	<.0001
HDD (t-1)	13419.4	<.0001	18762.2	<.0001	170770	<.0001
Jan	84.12	<.0001	84.29	<.0001	84.63	<.0001
Feb	27.68	<.0001	27.7	<.0001	27.73	<.0001
Mar	87.97	<.0001	88.15	<.0001	88.52	<.0001
Apr	740.71	<.0001	753.88	<.0001	781.85	<.0001
May	1412.97	<.0001	1461.4	<.0001	1570.3	<.0001
Jun	1767.59	<.0001	1843.82	<.0001	2020.6	<.0001
Jul	1864.41	<.0001	1949.35	<.0001	2148.1	<.0001
Aug	1820.23	<.0001	1901.13	<.0001	2089.7	<.0001
Sep	1512.24	<.0001	1567.81	<.0001	1693.8	<.0001
Oct	932.59	<.0001	953.52	<.0001	998.72	<.0001
Nov	281.4	<.0001	283.29	<.0001	287.15	<.0001

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Table 5: Eastern Region Test Statistics

	Likelihood Ratio		Wald		LM	
	Chi-Square	Pr > ChiSq	Chi-Square	Pr > ChiSq	Chi-Square	Pr > ChiSq
Intercept	2602.46	<.0001	2769.94	<.0001	3189.3	<.0001
HDD (t-1)	13930.5	<.0001	19740.4	<.0001	311310	<.0001
Jan	72.02	<.0001	72.14	<.0001	72.39	<.0001
Feb	4.6	0.0319	4.6	0.0319	4.61	0.0319
Mar	213.93	<.0001	215.02	<.0001	217.23	<.0001
Apr	1028.6	<.0001	1054.12	<.0001	1109.6	<.0001
May	1659.22	<.0001	1726.27	<.0001	1880.3	<.0001
Jun	1903.98	<.0001	1992.62	<.0001	2200.8	<.0001
Jul	1984.79	<.0001	2081.24	<.0001	2309.4	<.0001
Aug	1921.35	<.0001	2011.64	<.0001	2224	<.0001
Sep	1610.84	<.0001	1673.99	<.0001	1818.5	<.0001
Oct	1086.68	<.0001	1115.18	<.0001	1177.5	<.0001
Nov	393.29	<.0001	396.98	<.0001	404.6	<.0001

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Table 6: Niagara Region Test Statistics

	Likelihood Ratio		Wald		LM	
	Chi-Square	Pr > ChiSq	Chi-Square	Pr > ChiSq	Chi-Square	Pr > ChiSq
Intercept	1742.85	<.0001	1853.26	<.0001	2128.6	<.0001
HDD (t-1)	8689.48	<.0001	11947.9	<.0001	71865	<.0001
Jan	54.79	<.0001	54.9	<.0001	55.1	<.0001
Feb	27.83	<.0001	27.85	<.0001	27.91	<.0001
Mar	48.25	<.0001	48.33	<.0001	48.5	<.0001
Apr	448.75	<.0001	455.85	<.0001	470.83	<.0001
May	936.26	<.0001	967.52	<.0001	1037.6	<.0001
Jun	1199.99	<.0001	1251.66	<.0001	1371.5	<.0001
Jul	1277.32	<.0001	1335.98	<.0001	1473.4	<.0001
Aug	1243.9	<.0001	1299.48	<.0001	1429.1	<.0001
Sep	1043.22	<.0001	1082.13	<.0001	1170.5	<.0001
Oct	617.2	<.0001	630.69	<.0001	659.73	<.0001
Nov	186.99	<.0001	188.21	<.0001	190.72	<.0001

g)

i. As noted above, seasonal changes over the course of the year are captured by the monthly dummy variables and their lagged effects are captured through the auto-regressive term. Additionally, more precise seasonal impacts are captured in the Monte Carlo through the gas day-specific distributions.

ii. Navigant would say that the coefficient on HDD_{t-1} captures the fraction of HDD today that can be explained by HDD yesterday.

iii. See i., above.

iv. Subject to the random variation in the error term and adjusted by the coefficients on the monthly dummy variables, the specification of the AR model implies that the effects of given day's temperature on future days' temperature die down at approximately the same rate for any given day over the course of the period. The shocks themselves, it should be noted are *not* identically distributed for each day of the period, but rather vary by gas day (see further discussion in the Navigant report regarding the Monte Carlo analysis for more detail).

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BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D2 / Tab 4 / Sch 2 (Navigant Report)

At page 8 of the Navigant report, Navigant states: "The Autoregressive form of regression analysis was used to **identify** the relationship between one day's temperature and the next."

a) Which statistical tests for identification were conducted by Navigant in preparation of the Report to support this statement? Please provide the test statistics and p-values for these tests, stating all assumptions required to conduct each test.

b) Were any residual-based tests conducted to check for autocorrelation or heteroskedasticity in the residuals of the AR model? Please state which residual based tests were used, the test statistics from those tests, and the associated p-values. State any assumptions required to conduct each test.

RESPONSE

a) Please refer to the response to Board Staff Interrogatory #2 which can be found at Exhibit I, Issue D3, Schedule 1.2 a and d for a discussion of model identification and specification.

b) Navigant did not test or correct for residual heteroskedasticity as it was deemed not to have an impact on the analysis undertaken since it does not result in biased estimators (see below).

> "When heteroscedasticity is present, ordinary least-squares estimation places more weight on the observations with large error variances than on those with smaller error variances... Because of this implicit weighting, ordinary least-squares parameter estimators are unbiased and consistent but they are not efficient; i.e. the variances of the estimated parameters are not the minimum variances." - 6.1 Pindyck and Rubinfeld 4th Ed. 1998.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

Residual serial correlation was tested with Breusch-Godfrey test (sometimes also known as the Lagrange multiplier serial correlation test). For all three models the hypothesis that the residuals were not serially correlated was rejected with a high degree of confidence. Further tests were conducted including progressively higher order lags to determine how many lags would need to be included to achieve a test statistic that would allow the hypothesis of non-serial correlation to not be rejected.

It became apparent that, due to nature of the test statistic (which is a function of an auxiliary regression's unadjusted R2 and number of useable observations) achieving non-rejection of residual correlation would require an impractical number of lag orders.

Navigant estimated the severity of the serial correlation by regressing residuals from the models cited in the report on their own lagged values[1] and found that for all three regions the parameter estimate was less than 0.1, indicating a relatively low level of serial correlation. At this level of serial correlation, the bias introduced to the estimates is not substantial. Experimental work[2] with lagged-dependent variable models has found that with this level of residual serial correlation the bias on the lagged variable parameter is, with a sample size of 50, at worst overstated by 2%.

Given the sample sizes used for the three regions (several orders of magnitude greater than 50) and the therefore likely trivial bias, it was decided to use these models despite evidence of mild serial correlation in the residuals. Additionally, it was understood that whatever bias was introduced by this serial correlation would be compensated and corrected for by the gas day-specific distributions estimated as part of the Monte Carlo analysis.

[1] With the intercept term suppressed.
[2] Keele, L. *Dynamic Models for Dynamic Theories: The Ins and Outs of Lagged Dependent Variables,* Political Analysis, 14(2), Spring 2006

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D2 / Tab 4 / Sch 2 (Navigant Report)

At page 8 of the Navigant report, Navigant states: "All of the residuals from each of the 365 days of the year were then used to estimate a probability distribution of the random weather variation which might occur on that day of the year. The Monte Carlo simulations were calculated using the estimated parameters of the regression model, with a random shock applied in each period. **Each period's random shock was generated using the probability distribution estimated for that period using the regression equation residuals.**"

a) Please clearly state the **period** which Navigant used to generate the probability distribution for weather variation and from which the random shocks in the Monte Carlo simulation were drawn. Does the period refer to each calendar day in each year from 1957-2009? By way of example, does one "period" refer to the set of observations (January 1, 1957; January 1, 1958; . . .January 1, 2009), and the next "period" the set of observations (January 2, 1957; January 2, 1958; . . .January 2, 2009), and so on?

b) Please state whether the following is the correct interpretation of the steps Navigant took to conduct this Monte Carlo simulation:

Step 1. Calculate residuals from AR(1) model

Step 2. Using the residuals from each January 1 observation from 1957 to 2009, estimate a unique probability distribution associated with the date January 1.

Step 3. Repeat Step 2 for each of the remaining days in the sample (that is, January 2, January 3, up to December 31).

Step 4. Perform Monte Carlo simulation on each day of the sample (e.g., for each of January 1, January 2, up to December 31), using the estimated parameters from the AR model and with random shocks drawn from the distribution estimated for each day of the year in steps b and c.

Witnesses: J. Denomy
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J. Sarnovsky
D. Small

c) If the interpretation of the steps Navigant took to conduct this Monte Carlo Simulation above is not correct, please provide a comparable list of the steps Navigant took to conduct the Monte Carlo simulation. State any assumptions and clarify which days of each year and which years were used in both the estimation and simulation stages.

d) Board staff draws the conclusion from the above noted reference that Navigant estimated separate, unique probability distributions for weather variation on each calendar day of the year, which were then used in the Monte Carlo simulation. Please confirm Yes or No.

i. If the answer to d) is "yes," please state if Navigant agrees with the following statement:

Estimating separate probability distributions for each calendar day of the year implies that the variation in each calendar day's weather is assumed to be different on each calendar day of any given year, but the same on each calendar day from year to year.

If Navigant agrees with this statement, please explain why this approach to the Monte Carlo simulation is preferable to an approach in which the variation in each day's weather is not assumed to be different on each calendar day of the year.

If Navigant does not agree with this statement, please explain why Navigant disagrees and explain what assumptions Navigant has made about the variation of weather from one day to the next in a given year and on each day from year to year.

ii If the answer to D) is "no," please clearly describe the data which Navigant used to estimate each of the probability distribution(s) that were used in the Monte Carlo simulation. State any assumptions about the variation of weather across days and years required to use these estimated distributions in the Monte Carlo simulation.

RESPONSE

a) For each day[1] of the year, the residuals from the AR model were used to estimate a probability distribution. For example, for the Central region for January 1, the residuals from January 1, 1953, January 1, 1954, …, through to January 1, 2010

[1] A day was defined as a "gas day", the 24 hour period from 10 AM ET on one calendar day to 10 AM ET on the next calendar day. January 1 is the 24 hour period from 10 AM ET on January 1 to 10 AM ET on January 2.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

were used to estimate the probability distribution. For January 2, the residuals from January 2, 1953, January 2, 1954, …, January 2, 2010 were used, and so on. See Exhibit I, Issue D3, Schedule 1.2, Response b) for the data time periods for each region. Because the end goal of the Monte Carlo simulation was to generate a large number of winter period HDDs and to subsequently identify the peak day in the winter period, the probability distributions were determined for the period November 1 through March 31, rather than the full 365 days.

b) The corrections to the steps are stated in response c) below.

c) The steps of the Monte Carlo simulation are stated below:

Step 1. Calculate residuals from AR(1) model.
Step 2. Using the residuals from each January 1 observation from 1953 to 2010, estimate a unique probability distribution associated with the date January 1.
Step 3. Repeat Step 2 for each of the remaining days in the winter (that is, November 1, November 2, up to March 31). See response a) for explanation of reduction to winter time period.
Step 4. Perform Monte Carlo simulation on each day of the winter (e.g., for each of November 1, November 2, up to March 31), using the estimated parameters from the AR model and with random shocks drawn from the distribution estimated for each day of the year in steps 2 and 3.

d) Yes, Navigant estimated a unique probability distribution for weather variation on each day of the winter.

By using a unique probability distribution for weather variation on each day of the winter, Navigant chose not to make any apriori assumptions about the variation, but rather let the data determine the appropriate probability distribution. Navigant used the Crystal Ball software package to conduct the distributions fits and selected the appropriate distribution using the Anderson-Darling goodness-of-fit statistic. Additionally, this means that gradual seasonal shifts in temperature volatility are better captured than if the same distribution were assumed for each day of the year.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D2 / Tab 4 / Sch 2 (Navigant Report)

At page 9 of the Navigant report, Navigant states: "We examined the results for all three sites to validate the methodology. For the Central Region, the HDD Monte Carlo model reasonably predicted historical period normals. The daily normal HDDs for winter calculated from the Monte Carlo trial values were very close to those calculated from actual data. The largest daily absolute difference is 2.9%; over the entire period, the average absolute difference is 0.8%, as shown in the following chart. This gave confidence to apply the technique to the other two sites."

Did Navigant validate the methodology for all three sites or only for the Central region? Is Navigant relying only on the "confidence" it gained from the "validation" of the results for the Central region to justify the use of this methodology for the other regions?

RESPONSE

The Monte Carlo analysis was time consuming, so Navigant validated results from one region before applying the methodology to the other two regions for practical considerations. However, Navigant did validate the methodology for all three regions. This is summarized in Exhibit D2, Tab 4, Schedule 2, Table 4.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref(1) : Ex D2 / Tab 4 /Sch 2 (Navigant Report)
Ref(2): Ex D2 / Tab 4 /Sch 1
Ref(3): E.B.R.O. 490, Partial Decision with Reasons, August 29, 1995, Chapter 3, page 16
Ref(4) : Ex D1 / Tab 2 / Sch 3, p. 7
Ref(5): D2/T4/S2/ page 9

At Reference 1, in pages 24-25 (Appendix B) of the Navigant report, entitled "Multi-Peak Day Analysis Supplement," Navigant states on page 24 that: "The peak periods were defined in the same manners as Enbridge's existing multi-peak methodology." Navigant includes the results of the Multi-peak analysis in a table on page 25.

At Reference 2 on pages 1-2, Enbridge states, in relation to the current design day criteria, "The design day criteria has a multi-peak feature, in which six peak days in each high-demand month of January, February, and March are identified and planned for."

At Reference 3, para 4.20.2, the Board noted that "The Company [Consumers' Gas, now Enbridge] currently uses a single peak day design" with a recurrence interval of one in four years… The Company's new proposed Multi-Peak ("MP") design is based on a recurrence interval of one in five years, ("20 percent MP") which the Company claimed was somewhat more conservative than the current design…"

At reference 4, on page 7, line 18, Enbridge states: "Enbridge is seeking Board Approval to modify the Design Criteria. . . **The company is not proposing to change the multi-peak elements of the current Design Criteria. Rather, Enbridge is requesting a change to the values associated with each multi-peak as determined in the Design Criteria Study produced for the Company**. . . Enbridge is also requesting that the recurrence interval assumed for developing gas supply plans be lengthened from the current 1 in 5 recurrence to a 1 in 10 recurrence interval." Board Staff observes that the values Enbridge is proposing to adopt are the same as those

Witnesses: J. Denomy
Navigant
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reported in the Navigant study at reference 5, page 9, in the Table titled: "Monte Carlo Trial Distribution Fits for Design Day". (emphasis added)

a) Please state why Enbridge is proposing to adopt the values from the single peak HDD day study conducted by Navigant, as opposed to the values from the multi-peak study conducted by Navigant?

b) In E.B.R.O. 490 it was Enbridge's evidence that Multi-Peak is "more conservative" than the pre-1995 design, which used a single peak day design. In the current application, Enbridge and Navigant appear to make the opposite statement in adopting a single HDD value for each of the three regions. Please reconcile this seemingly contradictory evidence.

RESPONSE

a) Enbridge is not requesting a single peak Design Criteria. For clarity, Enbridge is requesting to update all of the values for each multi-peak within its Design Criteria for each of the three weather zones within its franchise area. As stated in Exhibit D1, Tab 2, Schedule 3, Page 7, Paragraph 18:

> "Enbridge is seeking Board approval to modify the Design Criteria it has been using since 1996. The Company is not proposing to change the multi-peak elements of the current Design Criteria. Rather, Enbridge is requesting a change to the values associated with each multi-peak as determined in the Design Criteria Study produced for the Company by Navigant which can be found at Exhibit D2, Tab 4, Schedule 2 and which is further described at Exhibit D2, Tab 4 Schedule 1. Enbridge is also requesting that the recurrence interval assumed for developing gas supply plans be lengthened from the current 1 in 5 recurrence interval to a 1 in 10 recurrence interval. Table 2 below shows the new peak day HDD values requested by the Company for each weather zone. The requested new multi-peak HDD values for each weather zone are set out in Appendix 1."

The Company is requesting to replace the multi-peak values set out in Appendix 1 of Exhibit D1, Tab 2, Schedule 3, page 20 under the columns entitled "Current Design Criteria" for each weather zone with the multi-peak values set out in the same appendix under the columns entitled "Requested Design Criteria" for each weather zone. Note the multi-peak values include the peak day HDD values and that the multi-peak values contained in Appendix 1 of Exhibit D1, Tab 2, Schedule 3, page 20 correspond to the multi-peak values outlined in Appendix B of Exhibit D2, Tab 4, Schedule 2, Page 25.

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Navigant
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b) Please see response to a). Enbridge is not requesting a single peak design criteria. Under a single peak Design Criteria storage balances would have to be maintained at a level which would ensure full deliverability from storage until some specified date, typically the end of February or March. Under the multi-peak Design Criteria, which the Company is not requesting be altered save for the values associated with each multi-peak, storage balances are not required to remain at levels which would ensure full deliverability to a specified date. Rather, storage deliverability, and thus storage levels, is allowed to fluctuate subject to the constraint that there remains enough storage deliverability to meet each of the multi-peak design conditions. Consequently, under the multi-peak Design Criteria the amount of gas carried in storage to a specified date will be less than the amount of gas carried in storage to a specified date if a single peak Design Criteria were used.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D1 / Tab 2 / Sch. 3

At line 20 on page 9 Enbridge states "Figures 1 through 3 show the coldest day, as measured by HDDs, in each of the three weather zones within the Company's franchise area . . . The trend line contained in each Figure shows that for all three weather zones peak HDDs have been following a slight downward trend."

At line 21 on page 10 Enbridge states "More importantly, however, peak HDDs have also exhibited an increase in volatility, particularly since the last update of the Company's Design Criteria. Table 2 compares the standard deviation of peak HDDs for the periods prior to and following 1994."

a) Board staff has difficulty assessing the statement "slight downward trend." Please test the statistical validity of this statement. Using a t-test, test the hypothesis that the slope of each line in the three Figures is equal to zero. Report the slope of each line, the standard error of the slope of each line, the test statistic and the p-value for the test statistic.
b) State whether Enbridge wishes to modify or withdraw the statement that "all three whether zones peak HDDs have been following a slight downward trend."
c) Please test the statistical validity of the statement "peak HDDs have also exhibited an increase in volatility". Using a t-test, test the hypothesis that the standard deviation from 1957-1993 is equal to the standard deviation reported for 1994-2009 for each region. Report the test statistic and the p-value for the test statistic. State any assumptions used to perform the test.
d) State whether Enbridge wishes to modify or withdraw the statement that "peak HDDs have also exhibited an increase in volatility."

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

RESPONSE

a) Please see below for the regression analysis for each weather zone.

Central

Sample: 1953 2010
Included observations: 58

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	37.83	0.80	47.21	0.00
CTREND	-0.05	0.02	-1.97	0.05
R-squared	0.07	Critical Value (Alpha=10%)	1.67	
Adjusted R-squared	0.05	Critical Value (Alpha=5%)	2.00	
S.E. of regression	3.01	Critical Value (Alpha=1%)	2.67	
F-statistic	3.90			
Prob(F-statistic)	0.05			

Eastern

Sample: 1953 2010
Included observations: 58

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	43.46	0.82	53.30	0.00
ETREND	-0.05	0.02	-2.21	0.03
R-squared	0.08	Critical Value (Alpha=10%)	1.67	
Adjusted R-squared	0.06	Critical Value (Alpha=5%)	2.00	
S.E. of regression	3.06	Critical Value (Alpha=1%)	2.67	
F-statistic	4.89			
Prob(F-statistic)	0.03			

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

Niagara

Sample: 1972 2010
Included observations: 39

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	35.40	0.88	40.16	0.00
NTREND	-0.08	0.04	-2.06	0.05

R-squared	0.10	Critical Value (Alpha=10%)	1.69
Adjusted R-squared	0.08	Critical Value (Alpha=5%)	2.03
S.E. of regression	2.70	Critical Value (Alpha=1%)	2.72
F-statistic	4.25		
Prob(F-statistic)	0.05		

Depending on the level of significance chosen the null hypothesis of a slope coefficient equal to zero may or may not be rejected for each weather zone. For example, at a 10% level of significance the null hypothesis of a slope coefficient equal to zero can be rejected for all three weather zones. At a 5% level of significance the null hypothesis of a slope coefficient equal to zero can be rejected for the Eastern and Niagara weather zones, however for the Central weather zone there is a marginal failure to reject the null hypothesis of a slope coefficient equal to zero.

b) Enbridge does not wish to withdraw or modify its statement. The statement that "…for all three weather zones peak HDDs have been following a slight downward trend" is an observation based on the direction of the trend line included in each of the graphs. The trend lines in each of the graphs show a negative slope which supports the observation that peak HDDs have been following a slight downward trend.

c) Please refer to Board Staff Interrogatory #1.1, part d at Exhibit I, Issue D3, Schedule 1.1 for the requested calculations.

d) Enbridge does not wish to withdraw or modify its statement. The statement that "…peak HDDs have also exhibited an increase in volatility, particularly since the

Witnesses: J. Denomy
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last update of the Company's Design Criteria" is an observation based on the standard deviations for peak HDDs for each of the three weather zones. The standard deviations calculated using the 1957 to 1993 period are lower than the standard deviations calculated using the 1994 to 2009 period which leads to the observation that, for these samples the standard deviations increased from one period to the next.

Witnesses: J. Denomy
Navigant
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex D1/T2/S3/p2

At paragraph 4 of the reference above, Enbridge states that, "Failing to assume an appropriate level of demand on peak day exposes a utility's gas supply plan to the risk of not being able to meet demand on that day as a result of not contracting for **sufficient** transportation and storage capacity or **ensuring appropriate levels of gas in storage**. The inability to meet peak day demand can result in low distribution system pressure or, in the extreme, system outages along with the economic implications of not having natural gas available for consumption." (emphasis added)

a) Please confirm based on the above statement that Enbridge's ability to meet critical peak days is function of, *inter alia,* gas in storage? If yes, please explain the implications of gas in storage on peak demand periods, including the effects that a reduced level of gas in storage has on distribution system pressure, if any. If there are critical thresholds, in reference to "in the extreme" above, for gas in storage, and potential effects on distribution system pressure, deliverability, and system outages, please provide these thresholds and comment on the likelihood that they could occur.

b) Provide the following information regarding peak level of gas in storage by Enbridge Gas at the outset of the heating season dating back to 2001:

	A	B1	B2	C1	C2	D(B1 - C1)
Heating season	Maximum available Gas Storage capacity	Peak Gas in storage (Bcf)	Date recorded	Minimum Gas in storage recorded in heating season	Date recorded	Net gas withdrawn/ (injected) during heating season

Witnesses: J. Denomy
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				(Bcf)		
2001/2002	…	…	…	…	…	…
2002/2003	…	…	…	…	…	…
…	…	…	…	…	…	…
2011/2012						

c) Please comment on Enbridge's use of Gas in Storage to serve its peak day requirements in recent years. Has Enbridge withdrawn less gas from storage on annual basis than in the pre-1995 period referenced in the Navigant report? The 2011/2012 heating season was a historically warm period, please comment on the level of withdrawal during the 2011/2012 heating season.

d) Enbridge notes in paragraph 5 that, "The addition of temperature sensitive loads increase variability in daily demand". However, is it not true that the same increase in residential customers compared to overall demand results in a *more* accurate near term forecast associated with severe cold weather events to plan for these events? (One might assume that cold weather events (and the associated demand peak) could be forecast days in advance, while other temperature insensitive loads could not be forecast with the same accuracy.

RESPONSE

a) Confirmed. The ability of the Company to meet demand during peak and near peak conditions is a function of the amount of gas in storage which impacts storage deliverability. In fact all components of the gas supply plan are critical to meet peak day demands.

Storage contracts will typically specify ratchets. Once the volume of gas in storage falls below a pre-determined level, withdraw capabilities are reduced. If the amount that can be withdrawn from storage is not sufficient to meet demand on a day Enbridge could draft on upstream pipelines potentially limiting the ability of those upstream pipelines to maintain minimum delivery pressures to Enbridge. In this case pressures in the Company's distribution system may be reduced. If pressures are reduced enough it may be the case that certain areas within the distribution network could fail to receive service. At a minimum, a lack of sufficient supplies from storage could incur load balancing charges on upstream pipelines.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Critical thresholds cannot be provided. Any critical threshold related to gas in storage and the impacts on distribution system pressure, deliverability, and system outages will be contingent on, but not limited to, the time of year, the amount of gas in storage, operational status of the distribution system and upstream pipelines and weather.

b) Please see the table below for the data requested. The Company is unable to provide data prior to the 2003/2004 heating season as this data are unavailable. The extent to which temperatures are warmer or colder at the outset of a particular winter and near the end of a particular winter will impact the amount of gas injected/withdrawn from storage and storage balances at the beginning and end of the winter.

In providing the requested data the Company has assumed that the reference to heating season refers to the November 1 to March 31 time frame. Consequently, the peak gas in storage may not be the highest for that particular heating season as in some years the greatest amount of gas in storage could occur in October. Likewise, the minimum amount of gas in storage may not be the lowest for that particular heating season as in some years the lowest amount of gas in storage could occur in April.

Storage Data (Bcf)

Heating Season	Maximum Available Gas Storage Capacity	Peak Gas in Storage	Date Recorded	Minimum Gas in Storage Recorded in Heating Season	Date Recorded	Net Gas Withdrawn / (Injected) During Heating Season
2003/2004	111.2	105.5	2-Nov-03	6.4	31-Mar-04	99.1
2004/2005	111.2	107.7	1-Nov-04	6.4	26-Mar-05	101.3
2005/2006	111.2	108.5	7-Nov-05	12.3	30-Mar-06	96.2
2006/2007	111.2	104.7	1-Nov-06	0.8	25-Mar-07	103.9
2007/2008	111.2	108.4	1-Nov-07	7.1	31-Mar-08	101.3
2008/2009	111.2	104.1	7-Nov-08	8.2	31-Mar-09	95.9
2009/2010	112.3	105.2	1-Nov-09	7.2	31-Mar-10	98.0
2010/2011	112.3	107.3	1-Nov-10	4.3	31-Mar-11	103.0
2011/2012	112.3	100.6	2-Nov-11	23.4	15-Mar-12	77.2

c) The amount of gas withdrawn from storage will vary from year to year depending on weather. The Company cannot comment on the amount of gas withdrawn from storage relative to the pre-1995 period as data for the pre-1995 period are not available.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Relative to prior years provided in the table above Enbridge withdrew less gas from storage during the 2011/2012 heating season due to the unseasonably warm temperatures experienced this past winter.

d) The Company would disagree with implication that as more temperature sensitive customers relative to temperature insensitive customers are added it becomes easier to forecast natural gas demand. The opposite is true. In general, the greater the variability of the variable being forecast the more difficult it is to forecast accurately. The lower the variability of the variable being forecast the easier it is to forecast accurately. Temperature sensitive demands by definition vary with temperatures and are therefore more variable than base load demand.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex D1/T2/S3/p3

Enbridge states that, "When an issue related to Design Criteria was raised in consultations in the "System Reliability" proceeding, it was suggested that the issue should be treated separately in a different proceeding. The Company has chosen to address the issue in this case."

a) Is it necessary for the Board to make a decision or otherwise approve a change to the Design Criteria in this proceeding?
b) Could this decision be made in a subsequent standalone proceeding?

RESPONSE

a) Yes. The Company believes it is necessary for the Board to make a decision and approve the requested change to the Company's Design Criteria in this proceeding. The Company is concerned with the level of risk associated with its current Design Criteria.

   In addition, during the System Reliability consultative the Company proposed to alter its Design Criteria. While the Company agreed to withdraw this proposal for purposes of effecting settlement in the System Reliability consultative, it is the Company's interpretation of the Settlement Agreement that the Design Criteria issue was to be dealt with in the next Cost of Service hearing for Enbridge, which is the case before the Board today.

b) Yes this decision could be made in a subsequent standalone proceeding if the Board chose to do so, however the Company believes the 2013 rates application is the appropriate venue for such a decision to be made. Please see the response to a) above.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: D1/T2/S3/p3

Enbridge states that, "[A] longer recurrence interval produces a less risky gas supply and transportation portfolio, all else equal, as a result of a higher peak day HDD assumption."

Please confirm that a "less risky" portfolio results in a more conservative gas supply plan and is accompanied by a significant increase in costs to customers. Has Enbridge surveyed its residential customers with respect to the incremental costs? (of both gas purchases/contracts and incremental infrastructure)

RESPONSE

Not confirmed. A "less risky" gas supply portfolio as a result of the Company's request does result in a more conservative gas supply plan. However, a less risky gas supply portfolio may not always be accompanied by a significant increase in costs to customers. The cost associated with any gas supply portfolio is dependent on the transportation and storage options available to the Company when it is developing its gas supply portfolio.

As stated in the Company's evidence at Exhibit D1, Tab 2, Schedule 1, page 5, the only viable option available to meet the increase in peak day demand resulting for the Design Criteria request is long haul TCPL STFT capacity. If any viable, but less expensive and equally reliable or more reliable, transportation option(s) were to become available prior to the commencement of the 2013 Test Year, the Company would analyze this option(s) and determine the fit within the gas supply portfolio. If it is determined that this alternative transportation option(s) is a good fit, the Company would presumably contract for this capacity thereby reducing the overall cost to customers while maintaining a gas supply portfolio of equal or lesser risk relative to the applied for gas supply portfolio. Please refer to Exhibit D1, Tab 2, Schedule 1, page 6 for a discussion of the proposed treatment of the incremental costs associated with the Design Criteria request.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Enbridge has not surveyed its residential customers with respect to the incremental costs associated with this particular request and application. In the event that it is required to do so, Enbridge would have to position the costs associated with an increase in peak day HDDs with the consequences on under designing its Design Criteria.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: D1/T2/S3/p5/para13

Enbridge states that "all other utilities surveyed utilize longer recurrence intervals in their Design Criteria. This means that of all utilities surveyed, Enbridge's Design Criteria are the riskiest."

a) Is it not necessary to know a number of properties of the comparator utilities, i.e. weather variation, storage availability and profile, geographic size or the service area, sources of supply, among other things, to make confirm the validity or invalidity of Enbridge's statement?

b) Is Enbridge's statement perhaps an over-simplification or over-generalization that would only be true if the comparator utilities had an *identical* profile (with respect to composition, availability of storage, weather "peakiness", etc.) to Enbridge? Please explain how Enbridge was able to conclude that Enbridge was the riskiest.

RESPONSE

a) No. Enbridge's statement is not an over-simplification or over-generalization nor is it necessary to know a number of properties of comparator utilities. Enbridge has applied for a change to its Design Criteria and Planning Design Criteria. It has not applied for wholesale changes to the manner in which it contracts for upstream transportation capacity or storage, nor has it applied for wholesale changes to the manner in which it designs its distribution system. The statement "all other utilities surveyed utilize longer recurrence intervals in their Design Criteria. This means that of all utilities surveyed, Enbridge's Design Criteria are the riskiest." is a statement of fact. Based on the Company's request and based on the results of the survey, Enbridge was able to conclude that its Design Criteria are the riskiest.

b) Please see the response to a) above.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #12

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Ex. D1/T2/S3/p17

At the reference Enbridge states that, "The Company is proposing to synchronize its Planning Design Criteria and Design Criteria with the exception of Peterborough which would remain at 46 HDDs." Enbridge has clearly identified three regions (Central, East, Niagara) for which it has requested distinct heating degree days.

Enbridge has provided no evidence to support this requested exemption, from the new Design Criteria, to apply to Peterborough. Please provide the reasons why Enbridge has proposed that Peterborough be exempted from Enbridge's Design Criteria.

RESPONSE

The Company wishes to make a correction to the statement referenced above. The statement should read "The Company is proposing to synchronize its Planning Design Criteria and Design Criteria with the exception of Barrie and Peterborough which would remain at 44 HDDs and 46 HDDs respectively."

In developing its gas supply plan the Company develops design demand conditions for each of the three weather zones within the franchise area. Distribution infrastructure however is designed based on HDD assumptions and design demand conditions for each of the areas within the franchise area. The Central weather zone is comprised of six distinct areas. The table on the following page compares the current and requested peak day HDD assumptions for the Company's current and requested Design Criteria and Planning Design Criteria.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Current HDD Planning Assumptions

Supply Planning	Design Criteria HDD Assumptions	Distribution Planning	Planning Design Criteria HDD Assumptions
		Area 10 Metro	41
		Area 20 Mississauga	41
		Area 30 Richmond Hill	41
		Area 40 Whitby	41
		Area 40 Peterborough	46
		Area 50 Barrie	44
		Area 60 Ottawa	47
		Area 80 Niagara	39
Central	39.5	Central	~41.3 (Weighted)
Eastern	45.1	Eastern	47
Niagara	36.3	Niagara	39

Requested HDD Planning Assumptions

Supply Planning	Design Criteria HDD Assumptions	Distribution Planning	Planning Design Criteria HDD Assumptions
		Area 10 Metro	43.7
		Area 20 Mississauga	43.7
		Area 30 Richmond Hill	43.7
		Area 40 Whitby	43.7
		Area 40 Peterborough	46.0
		Area 50 Barrie	44.0
		Area 60 Ottawa	50.7
		Area 80 Niagara	41.2
Central	43.7	Central	~43.8 (Weighted)
Eastern	50.7	Eastern	50.7
Niagara	41.2	Niagara	41.2

Witnesses: J. Denomy
J. Sarnovsky
D. Small

The Company is requesting to maintain the current Planning Design Criteria values for Barrie and Peterborough because it has traditionally designed the distribution system in these two areas to demand associated with 44 and 46 HDDs respectively. The Planning Design Criteria HDD values for these two areas are already higher than the requested Planning Design Criteria values and therefore do not need to be adjusted. The higher HDD assumptions for Barrie and Peterborough reflect the colder temperatures that are typically experienced in the Northern areas of the Company's franchise area. Not increasing the Planning Design Criteria values for Metro, Mississauga, Richmond Hill and Whitby to the requested HDD values would result in a situation where the amount of upstream capacity and thus supplies on peak day or during near peak conditions would be greater than the ability of the distribution system to take away these volumes.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #13

INTERROGATORY

Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref(1): Ex. D1/T2/S3/p7
Ref(2): Ex. D1/T2/S1/p6/para13

Enbridge indicates at Ref(2) that, "The impact on 2013 gas costs [of the change to PGDDC] would be an incremental $66.2 million or $74.5 million of unutilized transportation cost impacts in total."

a) Does the above estimate include the cost of incremental infrastructure associated with the higher requested heating degree day? If not, what are the gas *and* infrastructure implications that are tied directly to this additional volume of gas an throughput capacity.
b) Is the need for the GTA reinforcement project affected if the heating degree day forecast is not adjusted to 43.7 as in Enbridge's proposal?
c) Please provide additional gas supply requirements and incremental capital spending requirements associated with varying HDD for the Central Region.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Central Region – HDD / Design Criteria Sensitivity

Peak Day HDD	Incremental gas supply required (Bcf)	Cost of incremental gas supply	Cost of Incremental capital spending [1]	Total Cost associated with new Design Criteria ($)
39.5 (current)	0	0	0	0
40.0				
40.5				
41.0				
41.5				
42.0				
42.5				
43.0				
43.7(application)				

d) Repeat the table above for each of the Eastern and Niagara regions.

RESPONSE

a) No. The referenced estimate does not include the cost of additional infrastructure associated with the Company's Design Criteria request. Please see the response to c) below for the supply plan and infrastructure costs associated with the Company's Design Criteria request.

b) Please see response to Board Staff Interrogatory #3 which can be found at Exhibit I, Issue B1, Schedule 1.3.

c) Please see the tables below for the requested information. Note the amounts presented in each of the tables are cumulative. Consequently if there is no change from one degree day increment to the next no additional costs are required.

Additionally, the cost of incremental gas supply associated with the proposed change in Design Criteria will vary depending on the utilization of the incremental STFT throughout the winter. In other words the cost of incremental gas supply will, at a minimum, be the demand charge associated with the incremental 350,000 of

[1] i.e. Necessity to expand/build/reinforce distribution network with respect to Planning Design Criteria

Witnesses: J. Denomy
J. Sarnovsky
D. Small

STFT and commodity and fuel charges will vary with the load factor on the incremental STFT.

Furthermore, should an alternative transportation option(s) become available, demand charges could be reduced if tolls associated with this alternative(s) are lower. For example, while there is currently no short haul capacity available, if in future years short haul capacity does become available this option could be a less expensive alternative for displacement of peaking supplies relative to STFT.

In preparing this response the Company has assumed that the incremental STFT will be utilized fully for a period of ten days and contracted for from January 1 to March 31, a period of 90 days. The assumption of ten days of utilization is consistent with the manner in which the Company contracts for peaking supplies. Other assumptions include: An April 2012 QRAM price at Empress of $2.384/gj, a TCPL Empress to Eastern Zone toll of $2.24/gj, and a TCPL fuel ratio from Empress to the Eastern Zone of 2.40%. Note that the cost of incremental spending is not the revenue requirement associated with this cost but simply the extra capital cost required to reinforce the distribution network as a result of the changes in Design Criteria.

Central Weather Zone HDD/Design Criteria Sensitivity

Peak Day HDD	Incremental Gas Supply Required (gj/d)	Cost of Incremental Gas Supply ($ millions)	Cost of Incremental Capital Spending ($ millions)	Total Cost Associated with New Design Criteria ($ millions)
39.5 (Current)	0	0.00	0.00	0.00
40	32,288	7.30	0.00	7.30
40.5	64,576	14.59	0.00	14.59
41	96,863	21.89	0.00	21.89
41.5	129,151	29.19	0.00	29.19
42	161,439	36.49	0.00	36.49
42.5	193,727	43.78	0.05	43.83
43	226,014	51.08	0.17	51.25
43.7 (Requested)	271,217	61.30	1.63	62.93

Witnesses: J. Denomy
J. Sarnovsky
D. Small

Eastern Weather Zone HDD/Design Criteria Sensitivity

Peak Day HDD	Incremental Gas Supply Required (gj/d)	Cost of Incremental Gas Supply ($ millions)	Cost of Incremental Capital Spending ($ millions)	Total Cost Associated with New Design Criteria ($ millions)
45.1 (Current)	0	0.00	0.00	0.00
45.5	3,863	0.87	0.00	0.87
46	8,692	1.96	0.00	1.96
46.5	13,521	3.06	0.00	3.06
47	18,350	4.15	0.00	4.15
47.5	23,179	5.24	0.00	5.24
48	28,008	6.33	0.00	6.33
48.5	32,837	7.42	1.40	8.82
49	37,666	8.51	1.53	10.05
49.5	42,495	9.60	1.53	11.14
50	47,325	10.70	1.53	12.23
50.7 (Requested)	54,085	12.22	1.53	13.76

Niagara Weather Zone HDD/Design Criteria Sensitivity

Peak Day HDD	Incremental Gas Supply Required (gj/d)	Cost of Incremental Gas Supply ($ millions)	Cost of Incremental Capital Spending ($ millions)	Total Cost Associated with New Design Criteria ($ millions)
36.3 (Current)	0	0.00	0.00	0.00
37	3,602	0.81	0.00	0.81
37.5	6,175	1.40	0.00	1.40
38	8,748	1.98	0.00	1.98
38.5	11,321	2.56	0.00	2.56
39	13,894	3.14	0.00	3.14
39.5	16,467	3.72	0.00	3.72
40	19,040	4.30	0.56	4.86
40.5	21,613	4.88	0.56	5.44
41.2 (Requested)	25,215	5.70	0.56	6.25

d) Please see the response to c) above.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

BOARD STAFF INTERROGATORY #14

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: D1/T2/S4/p1-2

Enbridge reported approximately 22% non-compliance with curtailment instructions for the 'January 2011 incident' and 30% non-compliance with curtailment instructions for the 'February 2011 incident'.

a) In the Company's opinion, is the penalty associated with taking unauthorized overrun gas appropriate? In answering this question, please make reference to observed levels of non-compliance with the company's curtailment policies and how Enbridge intends to rectify this non-compliance.

b) Please comment on the potential effects on peak day gas requirements for non-compliance with curtailment periods.

RESPONSE

a) For clarity, penalties for non-compliance during a period of curtailment do nothing to help the utility manage the requirements during that period. Curtailment penalties are intended to drive behavior such that customers plan and prepare appropriately to be ready and able to comply. The more onerous the penalty, the greater the financial risk to customers for non-compliance.

Subsequent to the Settlement Agreement on System Reliability, as directed, Enbridge increased the cost for using overrun gas during curtailment to 150% of the highest price on each day the overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively. Enbridge also began withholding Curtailment Credits to customers who fail to comply (see response to FRPO Interrogatory #3 at Exhibit I, Issue D3, Schedule 8.3) with their curtailment obligations. Curtailment Credits are earned

Witnesses: B. Manwaring
J. Sarnovsky
D. Small

respective to a customers' deliveries during the months of December through March, and can represent hundreds of thousands of dollars for a large customer. Following discussions with customers who were assessed these penalties from the 2011 curtailment incidents, Enbridge is confident that these penalties are highly impactful to customers and garner attention at the customers' senior management level. Determining more accurately if the measures are appropriate won't be known with any greater certainty until demonstrated by further curtailment instances.

b) Enbridge expects compliance of its interruptible customers during a period of curtailment and as such includes curtailment volumes as part of its gas supply plan. If, for whatever reason, customers fail to meet their curtailment obligation, the impact on peak day would be dependent upon the severity of the non-compliance. The Enbridge Large Volume Distribution Contract also gives Enbridge the ability to shut off the supply of gas at the meter of customers who fail to comply with their curtailment obligation, as an event of default of the Large Volume Distribution Contract.

Witnesses: B. Manwaring
J. Sarnovsky
D. Small

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: D1/T2/S3

Please provide the terms of reference for the Navigant Study. What were the costs of the study and how are those costs to be recovered?

RESPONSE

Attachment 1 is Schedule "A" to the Consulting Services Agreement between Navigant Consulting, Inc. and Enbridge Gas Distribution Inc. dated March 22, 2011 which sets out the "Scope of Services" for the review and possible revision of the Company's design day criteria. Attachment 2 is the August 31, 2010 RFP issued by the Company requesting proposals to review and revise the Company's current design criteria. As Attachment 1 contains commercially sensitive information which the Company and Navigant view as confidential, the hourly rates of the individuals identified in Attachment 1 have been redacted. While the Company does not view these hourly rates as relevant for the purposes of this proceeding, in the event that the Board concludes otherwise, the Company hereby requests that the hourly rates of the individuals identified in Attachment 1 be treated in confidence in accordance with Rule 10 of the Board's Rules of Practice and the Board's Practice Direction on Confidential Filings.

To date total costs related to the Design Criteria Study are approximately $113,000. Of this amount approximately $4,500 plus additional costs related to work completed for this application will be recovered in rates for 2013.

Witnesses: J. Denomy
J. Sarnovsky

Schedule "A" to the Consulting Services Agreement between Navigant Consulting, Inc and Enbridge Gas Distribution Inc. dated March 22, 2011

Scope of Services:

The Consultant will review and revise design criteria for Enbridge.

Deliverables:

The Consultant will undertake the following activities as part of the core scope of work:

1. Review the basis for the 1995 design criteria currently being used by Enbridge.
2. Hold a half-day kick-off meeting / workshop with Enbridge to discuss Enbridge's desired refinements to the 1995 design criteria analysis, Navigant's proposed approach and demand data available from Enbridge.
3. Comparative analysis research into other gas utilities' "cold-weather" design criteria, Review findings with Enbridge and discuss implications for current analysis.
4. Collect weather data for all relevant weather stations, such as Pearson, St. Catharines and Ottawa, Peterborough and Barrie.
5. Statistical analysis of weather data for varying historic periods and resultant temperatures for design criteria for three areas (Central, Eastern and Niagara) with the potential for a further breakdown of EGD's Central area into Toronto, Peterborough and Barrie as warranted given differences in weather patterns within the Central area. Review findings with Enbridge and discuss implications for current analysis.
6. Understand potential impact of greater weather volatility going forward.
7. Econometric analyses to correlate available demand data to weather, customer mix, electricity generation, etc. with varying model specs and varying historical reference periods for each of the areas and subareas of interest to Enbridge.
8. Summarize findings in comprehensive draft report for Enbridge review.
9. Finalize report.

Navigant will also be available for any follow-up interrogatories or to serve as an expert witness in defending the methodology, results and conclusions of the report before regulatory or other bodies after completion of the final report. This "follow-on" support is not included in the core scope of work, but shall be provided on a time and material basis if requested by Enbridge.

Deliverable Dates:

The draft report shall be delivered at the end of November and the final report will be delivered at the end of December.

The deliverable dates may be extended at the discretion of Enbridge.

Term:

This service schedule shall be effective as of October 21, 2010 and expire April 30, 2011, or such other date as the parties may mutually agree.

Compensation and Key Personnel:

Project costs for the core scope of work described above inclusive of expenses (such as for travel and accommodations) shall not exceed $90,000, plus HST as applicable.

Project team and billing rates are as follows:

Principal in Charge – Todd Williams, [redacted] / hour
Associate Director – Ray Welch, [redacted] / hour
Managing Consultant – Rebecca Honeyfield, [redacted] / hour
Senior Consultant – Peter Steele-Mosey, [redacted] / hour

Provided Consultant is not in default of its obligations under the Agreement, fees are payable by Enbridge within thirty (30) days of receipt of an appropriately detailed invoice.

Service Standards:

Enbridge will be responsible for designating the nature of the services to be performed by the Consultant or verifying that the results achieved by the Consultant are satisfactory. The Consultant shall be obligated to follow Enbridge's specifications, standards and technical policies as revised by Enbridge from time to time (the "Standards") as they relate to the results of any particular consulting services. The Consultant need not follow the instructions of Enbridge as they relate to the means by and the manner in which any particular consulting services are to be accomplished provided that the work and services are in accordance with the Standards.

Limitation on Liability:

The parties agree that for the purposes of this Schedule "E", neither party shall be liable to the other for indirect, incidental, punitive, special or consequential damages arising out of the consulting services provided hereunder, even if the party has been informed of the possibility of such damages, including but not limited to, loss of profits, loss of

revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind. However, this limitation shall not apply to damages of any kind related to criminal, intentional, or reckless conduct on the part of either party.

Notwithstanding anything herein to the contrary, the total liability of Consultant, its parents, subsidiaries, affiliates, officers, employees or agents, for all claims of any kind arising under this Agreement, whether in contract, tort or otherwise, shall be limited to the total fees paid to Consultant under this Agreement.

Dated this 29th day of April, 2011

APPROVED AS TO FORM
ENBRIDGE LAW

Enbridge Gas Distribution Inc.

By: _____
Jim Grant
Vice President, Energy Supply, Storage Development & Regulatory

By: _____
Marc Weil
Director, Human Resources & Facilities

Navigant Consulting, Inc.

By: _____

Name: Todd Williams
Title: Director, Navigant Consulting, Inc.

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August 31, 2010

File Number: File

Request for Proposal: Review & Revise Design Criteria for EGD

Enbridge Gas Distribution Inc. (EGD), a wholly owned subsidiary of Enbridge Inc., is the largest natural gas distribution LDC in Canada, serving over 1.9 million customers mainly in the Greater Toronto Area, Niagara and Ottawa regions of Ontario. EGD is also the fastest growing utility in Canada, adding tens of thousands of primarily residential customers each year. EGD's current annual demand is about 420 billion cubic feet (Bcf). Its peak day demand is approximately 3.5 Bcf. Most of the natural gas supplies to the EGD franchise currently come from the Western Canadian Sedimentary Basin (WCSB) and transported through TransCanada's Mainline Pipeline, or via the Alliance and Vector Pipelines systems. Some of the EGD supplies are also US sourced and purchased from the Chicago or Dawn hubs.

Gas utilities serving in cold climates, such as that of Ontario, plan to meet daily, seasonal and annual gas requirements using a carefully developed design criteria. The objective of the design criteria is to provide a high degree of assurance in system integrity and supply reliability at a reasonable cost to rate payers. Two critical criteria that affect the natural gas portfolio and distribution network planning are: design day and design hour.

EGD currently uses -21.5 degree Celsius or equivalently 39.5 degree days for design day, and 41 degree days for the design hour. EGD's design day was developed in 1994/95 and assumes a level of risk equal to 20% (or a probability occurrence of 1 in 5 years.) Design hour has a 5% or 1 in 20 year probability occurrence. EGD wishes to review and revise its design criteria to better reflect weather and current demand and market conditions.

Many market changes have occurred since 1995 including: a) increased heat-sensitivity of the EGD customer base because of adding predominantly residential and small nonresidential customers. Since 1995, EGD has added over 700,000 residential customers; b) perceived higher volatility in weather relative to the long term average; c) more restrictive operating parameters on upstream pipelines; and d) increased use of natural gas for power generation in the franchise.

EGD is seeking assistance from an energy consulting firm, with demonstrated expertise in statistical and probabilistic analyses of weather and energy as well as regulatory expertise to help with the development of new design criteria for EGD.

Scope of Work:

- Review EGD's existing design criteria and revise the criteria for EGD using relevant weather and demand analyses including but not limited to temperature, wind, hours of sunlight, and humidity.
- Determine design day and hour degree day levels for EGD's Central, Eastern and Niagara areas.
- Prepare comparative analysis of the relevant Canadian and U.S. LDCs.
- Provide expert witness at the Ontario Energy Board in defending methodology, results and conclusions of the new design criteria.

Key Deliverables:

- Participate at a half day workshop at the outset to discuss existing criteria, methodologies, data and assumptions. This workshop will be held in Toronto, Ontario.
- Ongoing consultation to discuss preliminary results; provision of recommended revisions to methodology and assumptions.
- Assessment of the final results.
- Comprehensive report.
- Project completion before the end of 2010.

Response:

Should you be interested in providing this service to EGD, please submit a proposal stating the extent to which you can fulfill EGD's requirement, your service attributes including regulatory experience, and your pricing estimate and terms.

Please submit your proposal no later than **12:00 pm Eastern Daylight Time on September 15, 2010** to the attention of Hilmi Muhammad at the email address and/or fax number provided below.

Ph: 403 508 3187
Fax: 403 231 5770
hilmi.muhammad@enbridge.com

Should EGD decide to proceed with this project, it will be necessary to execute a "Consulting Service Agreement" that will detail the terms and conditions related to the project, and a "Confidentiality Agreement" between EGD and the successful candidate.

If you have any questions regarding this RFP, please feel free to call me.

Yours truly,

Hilmi Muhammad

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Exhibit D2, Tab 4, Schedule 2, Table 1

a) Please confirm that the 1994 through 2009 column did not use data for the winter of 2009/2010 because it was not available at the time the study was done. If this cannot be confirmed, please explain why 2010 was not included in the analysis.

b) Please update Table 1 to include a column for 1994 through 2012, given that the data for the winter of 2011/2012 is now available.

c) Please add a column to Table 1 that utilizes data for 1996 through 2012.

RESPONSE

a) Confirmed. Based on the data provided to Navigant by Enbridge the 1994 to 2009 column did not use data for the winter of 2009/2010 because it was not available. The data provided by Enbridge included information to September of 2010 and not beyond. It should be noted that the data in Table 1 are calculated and compiled based on a January 1 to December 31 timeframe, or calendar year, for each year contained in the sample identified. Consequently, complete data for 2010 were not available when this analysis was conducted and therefore data for 2010 was not included in Table 1. Table 1 contains data for the Enbridge Central Weather zone only.

b) Note that analysis of any sample including data for the year 2012 cannot be completed at this time as data for 2012, based on a calendar year, are not yet available.

Please see the table below which has been updated to include data to 2011.

Witnesses: J. Denomy
R. Honeyfield
Navigant Consultant

Annual Peak HDD Normals		
Heating Degree Days	**1957 Through 1993**	**1994 Through 2011**
Period (Years)		
Minimum	34.21	29.26
Average	37.38	35.14
Maximum	42.76	44.07
Standard Deviation	2.24	3.70
Coldest Day	3-Jan-81	15-Jan-94
Warmest Day	15-Feb-91	30-Dec-98

c) Please see the table below which has been updated to include data to 2011 and altered to utilize the sample ranges 1957-1995 and 1996-2011.

Annual Peak HDD Normals		
Heating Degree Days	**1957 Through 1995**	**1996 Through 2011**
Period (Years)	**39**	**16**
Minimum	34.21	29.26
Average	37.56	34.43
Maximum	44.07	39.08
Standard Deviation	2.43	3.03
Coldest Day	15-Jan-94	9-Jan-04
Warmest Day	15-Feb-91	30-Dec-98

Witnesses: J. Denomy
R. Honeyfield
Navigant Consultant

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Ref: Exhibit D1, tab 4, Schedule 2, Table 3

a) Please confirm that the data in Table 3 is based on an analysis of data for period January 1953 to September 2010 for the central and eastern regions and of data for period January 1, 1971 through September 2010 for the Niagara region. If this cannot be confirmed, please provide the period of data used in the analysis for each region.

b) Please provide a version of Table 3 that extends the period of the data used to include data through April 2012.

c) Please provide a version of Table 3 that reflects the analysis that would result from using the most recent:

   i) 20 years of data for each region;
   ii) 30 years of data for each region; and
   iii) 40 years of data for each region.

RESPONSE

In responding to this interrogatory the Company has assumed that Energy Probe is referring to Exhibit D1, Tab 2, Schedule 3, page 10, Table 3.

a) Not confirmed. Table 3 was designed to show the standard deviations for all three weather zones within the Enbridge franchise area. The data in Table 3 is based on an analysis of data for the period January 1957 to December 2009 for the Central and Eastern weather zones and January 1972 to December 2009 for the Niagara weather zone. The standard deviation data in Table 3 under the column entitled

Witnesses: J. Denomy
R. Honeyfield
Navigant
J. Sarnovsky

"Central" correspond to the data provided by Navigant Consulting at Exhibit D2, Tab 4, Schedule 2, Page 7, Table 1. The "Eastern" and "Niagara" columns simply extend the standard deviation elements of Table 1 of the Navigant Consulting Design Criteria Report to include the additional weather zones within the Enbridge franchise area.

b) Analysis of any sample including data for the year 2012 cannot be completed at this time as full year data for 2012, based on a calendar year, are not yet available.

The table below provides an update to Table 3 which includes data from 1957-2011 for the Central and Eastern weather zones and 1972-2011 for the Niagara weather zone.

Standard Deviation of Peak HDD

Period	Central	Eastern	Niagara
1957-1993	2.2	2.8	2.6
1994-2011	3.7	3.6	2.9
Change	64.6%	27.4%	12.6%

Note: Niagara uses data from 1972-2011.

c) The table provided on the following page provides the standard deviations for each weather zone for the periods requested.

Witnesses: J. Denomy
R. Honeyfield
Navigant
J. Sarnovsky

Standard Deviation of Peak HDD			
Period	**Central**	**Eastern**	**Niagara**
20 Years			
1992-1993	0.5	1.1	1.7
1994-2011	3.7	3.6	2.9
Change	688.8%	215.6%	74.4%
30 Years			
1982-1993	1.7	2.5	1.6
1994-2011	3.7	3.6	2.9
Change	123.4%	42.5%	84.2%
40 Years			
1972-1993	2.5	2.8	2.6
1994-2011	3.7	3.6	2.9
Change	46.6%	31.5%	12.6%

Witnesses: J. Denomy
R. Honeyfield
Navigant
J. Sarnovsky

FRPO INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Preamble: Within each 5 day bracket a multi-peak was placed on the day determined to be the coldest average day within that bracket. The peak day HDD value was placed on January 15, historically the coldest day on average in the winter. Additionally, January 15 was designed to occur on a week day. The rationale for imposing peak day HDD to occur during a week day arises from the observation that demand on weekdays is higher than demand on weekends, and therefore weekdays are more suitable for supply planning.

By fixing a coldest day on January 15th, statistically, what error is added by assuming that the coldest day is a weekday?

a. If assumed a weekend, please provide a detailed list of the changes in design requirement changes that would result from a change in the base assumption.

RESPONSE

There is no additional error or risk added by assuming the coldest day of the year occurs on a weekday. The opposite is true. Assuming the coldest day of the year and peak day demand occur on a weekday (Monday to Thursday) relative to a weekend (Friday to Sunday) adds, on average, approximately 58,000 gjs to peak day demand. Risk associated with being able to meet this incremental demand is dependent on the nature of the transportation and/or supply used to meet this demand.

Witnesses: J. Denomy
J. Sarnovsky
D. Small

FRPO INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Reference: D1, Tab 2, Schedule 1

Preamble: As a part of its Gas Supply evidence for 2012 (EB-2011-0277, Exhibit B, Tab 4, Schedule 1, page 4, paragraph 11) the Company discussed reasons why it reduced its overall level of traditional Peaking Services as part of its gas supply portfolio for 2012. The Company believes that the failure to deliver during periods of high demand in January and February of 2011 are justification to maintain the same level of Peaking Supplies for 2013 as was forecast for 2012.

Please provide the cost consequences of the “failure to deliver during periods of high demand in January and February of 2011" to ratepayers.

RESPONSE

Cost consequences of the “failure to deliver during periods of high demand in January and February of 2011" are difficult to determine. As was pointed out by Mr. Small in a discussion with Mr. Quinn in EB-2011-0277 proceeding in the transcript on January 24 at pg 31:

> MR. QUINN: I want to break down your answer a little bit further so that we better understand, and then move forward again.
>
> You said in January 2011 you had an incident of failure to deliver and there were significant penalties.
>
> First, did Enbridge nominate additional gas on that day to replace the peaking services that were not delivered?
>
> MR. SMALL: On that particular day we did not have to, no. We were able to manage it through the supplies coming in, and looking back, the -- one thing you kind of have to remember is that we are going to be -- gas control, for example, would be looking at what the expected demand forecast is going to be for the day ahead, and they are going to nominate for their supplies.

Witnesses: J. Sarnovsky
D. Small

Now, when you get to the gas day, the demand may not be as high as you thought it was and you sometimes can manage that demand if some of your supplies didn't show up.

Now, we were lucky enough on this particular day that the demand did drop off a little bit so we didn't have to go out and acquire additional supplies.

However, it is possible to determine a hypothetical cost. For example, if we examine the cuts that occurred in the month of January 2011 as the table below shows and we assume a price of $5.166/gj, the value of the cuts was $145,000 and the value of the peaking service that was cut would be $35,400 but this would be offset by the penalty charged to the peaking supplier of $80,700.

	Gas Daily Jan 24 - Niagara $/mmbtu - highest price on the day				
$/mmbtu	5.450				
$/gj	5.166				
	CDA Cuts				
	22-Jan	23-Jan	24-Jan		
GJ's	7,160	18,517	2,396		28,073
Imputed value of non- delivery	36,985.71	95,651.46	12,376.78		145,013.96
	Peaking Cuts				
	22-Jan				
	6,852		Penalties for non- delivery		
Imputed value of non- delivery	35,394.71		(80,750.29)		

These hypothetical costs would have gone to the PGVA for collection from customers. However the UOG penalties and the curtailment credit (as discussed in response to FRPO Interrogatory #3 at Exhibit I, Issue D3, Schedule 8.3) also went to the PGVA.

For clarity, penalties for non-compliance during a period of curtailment do little to help the utility manage the requirements during that period. Curtailment penalties are intended to drive behavior such that customers plan and prepare appropriately to be ready and able to comply. The more onerous the penalty, the greater the financial risk to customers for non-compliance.

Witnesses: J. Sarnovsky
D. Small

FRPO INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Reference: D1, Tab 2, Schedule 4, page 1-2

The Settlement Agreement directed Enbridge to, among other things, change the wording of the Rate Handbook to state that, when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment, the customer will forfeit its curtailment credits for the respective winter season of December through March inclusive. Further changes to the wording of the Rate Handbook for Rate 145 and 170 should state that customers have a demonstrated capacity to cease or reduce operations, or to utilize a backup fuel, in order to curtail their consumption of natural gas in accordance with a curtailment notice. The Rate Handbook wording was also changed to state that, when a customer takes Supply Overrun Gas, the customer shall purchase gas at 150% of the highest price on each day on which the overrun occurred. The Settlement Agreement also directed that Interruptible service on 72 hours notice under Rate 145 be eliminated.

For the two incidents of 2011, please show the calculations that created the penalties for Unauthorized Overrun Gas.

RESPONSE

The requested calculations are based on the following:

Calculating Unauthorized Overrun Gas ("UOG")

The UOG calculation for each customer is: (UOG Volume) x (UOG price on the day) and was derived from the following data:

- There were 64 individual customers who took UOG on one or multiple days of the January and February 2011 curtailment periods.
- The sum total of the volume of UOG was (Jan. 633,415m^3, and Feb. 590,289m^3) 1,223,704m^3

Witnesses: B. Manwaring
J. Sarnovsky
D. Small

- There were 7 days of curtailment in 2011 (5 in January, and 2 in February)
- Curtailment UOG prices (based on each day of the incident) ranged from $\$0.240363/m^3$ to $\$0.330132/m^3$.

Calculating Curtailment Credit Withholding

The Curtailment Credits impacts were derived from the table on the following page, considering information below:

- As per the Settlement Agreement, "when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment, the customer will forfeit its curtailment credits for the respective winter season of December through March inclusive." Enbridge determined that any volume of gas consumed beyond one hour after the curtailment notification period (4 hours for Rate 170, and 16 hours for Rate 145) would constitute "material volume", so be subject to having Curtailment Credits withheld. One hour is approximately 4% of the customer's daily Contract Demand. The number of months of Credits withheld was a function of the volume of UOG each customer consumed, as per the table on the following page.
- The total number of "months" of Curtailment Credits that were withheld in 2011 was 112.
- The sum value of these Curtailment Credits was $2,009,110.00

Consuming During Curtailment Charges:

Deliver Full MDV	Consume nothing	No penalty
Deliver Full MDV	Consume < 4% of CD	UOG on the consumption
Deliver Full MDV	Consume > 4% of CD but < 10% of CD	UOG on the consumption, plus one month of Curtailment Credit
Deliver Full MDV	Consume > 10% of CD but < 40% of CD	UOG on the consumption, plus Two Months of Curtailment Credit
Deliver Full MDV	Consume > 40% of CD	UOG on the consumption, plus Four months of Curtailment Credit

Failure to Deliver MDV

Fail to deliver < 4% of MDV on a day		No Credit Impact
Fail to deliver > 4% of MDV but < 100% of MDV on a day		Two months of Curtailment Credit
Fail to deliver 100% of MDV on a day		Four months of Curtailment Credit

Witnesses: B. Manwaring
J. Sarnovsky
D. Small

FRPO INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

Reference: D1, Tab 2, Schedule 4, page 1-2

The Settlement Agreement directed Enbridge to, among other things, change the wording of the Rate Handbook to state that, when a customer takes a material volume of Unauthorized Supply Overrun Gas during a period of ordered curtailment, the customer will forfeit its curtailment credits for the respective winter season of December through March inclusive. Further changes to the wording of the Rate Handbook for Rate 145 and 170 should state that customers have a demonstrated capacity to cease or reduce operations, or to utilize a backup fuel, in order to curtail their consumption of natural gas in accordance with a curtailment notice. The Rate Handbook wording was also changed to state that, when a customer takes Supply Overrun Gas, the customer shall purchase gas at 150% of the highest price on each day on which the overrun occurred. The Settlement Agreement also directed that Interruptible service on 72 hours notice under Rate 145 be eliminated.

Please provide a table with the same layout that shows the 2012 experience with interruptions of these customers.

a. If there were no interruptions, please explain why by comparison to 2011 circumstances.

RESPONSE

The overall weather for 2012 was warmer than budget and the Company did not experience any incidences when curtailment needed to be called.

Witnesses: B. Manwaring
J. Sarnovsky
D. Small

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 3: Are the proposed changes to Peak Gas Day Design Criteria (PGDDC) and methods of cost recovery appropriate?

References: Exhibit D1 Tab 2 Schedule 3 Page 7
Exhibit D2 Tab 4 Schedule 1 Page 5

a) Please provide an equivalent chart/figure for the current methodology.

b) Compare the current (old) methodology (no wind speed Variable) vs new Methodology.

c) Delineate the effect of including Wind Speed in the modified HDD calculation-Statistics --with/without for each region.

d) How many Canadian Utilities include a wind speed variable in the HDD calculation? Please list any that do.

e) What are the cost consequences of adopting the proposed Peak Day Design Criteria?

RESPONSE

a) The Company interprets this interrogatory to be requesting what the comparable peak day HDD values would be under the Company's existing approach to determining HDD values for its design criteria.

The tables below provide the peak day HDD values, utilizing the Company's current methodology, associated with various recurrence intervals for the sample ranges 1953 to 2009 and 1953 to 2011. Data for Niagara prior to 1972 are not available therefore the Niagara peak day HDD values are derived using the sample ranges 1972 to 2009 and 1972 to 2011. The 1953 to 2009 sample was selected as it corresponds to the time frame utilized by Navigant Consulting to conduct the Design

Witnesses: J. Denomy
R. Honeyfield, Navigant
J. Sarnovsky

Criteria Study. The 1953 to 2011 sample was selected as this time frame incorporates the most recent data available.

Peak Day HDD Design Criteria Values Utilizing Existing Methodology

Weather Zone:	**Central**				
Recurrence Interval:		**1 in 5**	**1 in 10**	**1 in 20**	**1 in 100**
$P(HDD_{Observed} > HDD_{Design\ Criteria})$:		**20%**	**10%**	**5%**	**1%**
Sample:	1953-2009	39.1	40.5	41.7	43.9
	1953-2011	39.1	40.4	41.6	43.8

Weather Zone:	**Eastern**				
Recurrence Interval:		**1 in 5**	**1 in 10**	**1 in 20**	**1 in 100**
$P(HDD_{Observed} > HDD_{Design\ Criteria})$:		**20%**	**10%**	**5%**	**1%**
Sample:	1953-2009	44.6	46.1	47.2	49.5
	1953-2011	44.6	46.0	47.2	49.4

Weather Zone:	**Niagara**				
Recurrence Interval:		**1 in 5**	**1 in 10**	**1 in 20**	**1 in 100**
$P(HDD_{Observed} > HDD_{Design\ Criteria})$:		**20%**	**10%**	**5%**	**1%**
Sample:	1972-2009	36.3	37.6	38.6	40.7
	1972-2011	36.2	37.5	38.5	40.6

b) A comparison of the current methodology versus the new methodology can be found at Exhibit D1, Tab 2, Schedule 3, pages 14 to 17. Note the Company is not requesting, at this time, that an adjustment for wind speed be incorporated into its Design Criteria HDD values.

c) The Company has not developed a study to determine and incorporate the impact of wind speed on the requested design criteria heating degree day values.

Incorporation of wind speed effects into the HDD calculation would create an "effective" HDD value which would compensate for the impact of wind speed on design demands. While the Company has not studied the impact of wind speed on peak day HDDs, the following provides a very simplistic estimate of wind

Witnesses: J. Denomy
R. Honeyfield, Navigant
J. Sarnovsky

speed impacts on peak day HDDs:

A rough rule of thumb that can be used is that every 10 km/hr of wind adds approximately 0.5 HDDs of demand. Average wind speed for each winter from 1953-2009 is approximately 17.1 km/hr, 15.1 km/hr and 19.1 km/hr for the Central, Eastern and Niagara weather zones, respectively. Based on the Monte Carlo simulations conducted by Navigant Consulting at Exhibit D2, Tab 4, Schedule 2, page 9, Table 3 and the aforementioned rule of thumb, the following "effective" peak day HDD values would result:

	Requested Peak Day HDD	Average Winter Wind Speed (1953-2009)	1 in 10 Wind Speed	Degree Day Increment	Adjusted Peak Day HDD Value
Central	43.7	17.1	24.8	0.4	44.1
Eastern	50.7	15.1	26.4	0.6	51.3
Niagara	41.2	19.1	26.8	0.4	41.6

Note: Niagara uses data from 1972-2009.

d) The Company has not surveyed all Canadian utilities and is therefore unable to provide the number of Canadian utilities that utilize a wind speed variable in the derivation of design criteria HDD values.

However, respondents to the design criteria survey conducted by Navigant on behalf of the Company can be found at Exhibit D2, Tab 4, Schedule 2, page 14. Two Canadian utilities were surveyed and responded to the design criteria survey.

Of these two utilities one was Union Gas which resides in Ontario. Union Gas utilizes effective degree days when determining its design criteria. As discussed in the response to c) above, effective degree days are degree days compensated for wind speed impacts. It should be noted for the Southern portion of the Union Gas franchise, Union utilizes a peak day effective HDD value of 44 when determining design demand. This value corresponds to about a 2% to 1% probability of being exceeded in any given year.

The other Canadian utility that responded to the design criteria survey was GMi. Situated in Quebec, GMi also utilizes a wind speed variable when determining its design demand. However, wind speed is not factored into the peak day HDD value. Rather it is treated as a separate variable when determining design demand. GMi also includes HDD variables for the day of and the prior day when determining design demand. For 2012 these HDD values are 36.9 and 39.5,

Witnesses: J. Denomy
R. Honeyfield, Navigant
J. Sarnovsky

respectively. GMi degree days are calculated on a balance point of 13 degrees celcius. On a balance point of 18 degrees celcius these degree day values are equivalent to 41.9 degree days and 44.5 degree days, respectively.

e) Please see the response to Board Staff Interrogatory #13c which can be found at Exhibit I, Issue D3, Schedule 1.13 for the cost consequences associated with adopting the requested Design Criteria.

Witnesses: J. Denomy
R. Honeyfield, Navigant
J. Sarnovsky

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref(1): Ex. A2/Tab3/Sch 2/Appendix A Mercer Report, Updated Estimated 2013-2017 Accrual Costs – EGD Pension Plans – 01 June 2012

Ref(2): Ex. A2/Tab3/Sch 2/Appendix B Mercer Report, Updated Estimated 2013-2017 Cash Funding Costs – EGD Pension Plans – 01 June 2012

a) Has EGD's external auditor audited or reviewed Appendix A and Appendix B prepared as at June 1, 2012, including the assumptions used?

   i. If so, do the reports reflect the auditor's comments?

   ii. If not, when will the external auditor's audit or review take place?

b) Have these documents been filed with the FSCO or CRA?

   i. If so, have comments been received form the FSCO or CRA?

RESPONSE

a) No, the external auditors have not reviewed Appendix A or B. These reports contain estimates for the periods 2013 through 2017 which EGD's auditors would not have reviewed as it would not impact actual year end results. As actual pension expense arises in the years 2013 to 2017 EGD's external auditors will review any supporting Mercer reports at that time.

b) No, these documents have not been filed as it is not a FSCO or CRA filing requirement.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. D1/Tab 3/ Sch 2/ Page 6 & 7

a) Regarding the increase in Pension Expense from 2011 to 2012 and from 2011 to 2013, please explain if this increase due to the approximate $17 million Z-factor for pension contributions which was denied in the EB-2011-0277 Board decision.

ii. If so, why should the Board grant recovery of the approximate $17 million amount in this proceeding if it was denied in EB-2011-0277?

RESPONSE

Annual pension expense is incurred specifically in relation to each fiscal year. The Z-factor request in 2012 was a request for the recovery specific to the annual pension expense incurred in 2012. The annual pension expense amount for 2013 is the amount of expense that will be incurred in 2013 in relation to Pension rules and requirements.

Please see the response to Board Staff Interrogatory #6 at Exhibit I, Issue D1, Schedule 1.6 explaining the recoverability of this 2013 related amount.

Witnesses: S. Chhelavda
K. Culbert
A. Patel
S. Trozzi
B. Yuzwa

BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 2/ Appendix B to Appendix B/ Estimated 2013-2017 Cash Funding Costs – EGD Pension Plans – 26 October 2011

a) Please provide a copy of EGD's annual Actuarial Cost Certificate as at January 1, 2012.

b) Has EGD's external auditor audited or reviewed the January 1, 2012 Actuarial Cost Certificate, including the assumptions used?
   iii. If so, does the report reflect the auditor's comments?
   iv. If not, when will the external auditor's audit or review take place?

RESPONSE

a) An actuarial cost certificate is only filed if the pension plan is in a surplus position. EGD's pension plan was in a deficit position as at December 31, 2011 therefore a cost certificate was not prepared and filed.

b) Since no cost certificate was prepared EGD's external auditors did not review any such document.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: EB-2011-0277 Oral Hearing Transcript, January 24, 2012, page 128

Ex. A2/ Tab 3/ Sch 2/ Page 2 & 3

EGD is proposing to switch to the accrual basis from the cash basis for regulatory purposes for pension in this proceeding, effective January 1, 2013. In EB-2011-0277 Oral Hearing Transcript, January 24, 2012, page 128, line 17-19, EGD referenced that under USGAAP, EGD may be able to remain on the cash basis for pension for financial reporting purposes.

a) Please provide the reference in the USGAAP standards which would allow EGD to record pension costs on a cash basis for financial reporting purposes.

b) If the cash basis is used for both financial reporting and rate-making purposes for pension, please list the advantages and disadvantages to ratepayers and to EGD.

c) EGD has listed the general benefits and ratepayer impact of using the accrual basis for pension expense for financial reporting purposes and regulatory purposes at Ex. A2/ Tab 3/ Sch 2/ Page 2 and page 3. Please specifically list the advantages and disadvantages to ratepayers and to EGD if the accrual basis is used for both financial reporting and rate-making purposes for pension.

d) If the accrual basis is used for financial reporting purposes and the cash basis is used for regulatory purposes for pension, please list the advantages and disadvantages to ratepayers and to EGD.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

RESPONSE

a) Under US GAAP pension expense has to be recorded on an accrual basis, however US GAAP standard 980-715-25-1 (Regulated Operations Compensation – Retirement Benefits) allows a rate regulated company to be on an equivalent to cash basis of expense by the creation of an asset or liability to capture the difference between the accrual basis of expense and that which is used for rate making purposes.

b)

Ratepayer – Advantage:	In years where no contribution is required the current ratepayers would benefit as there would be no expense to be recovered in rates.
Ratepayer – Disadvantage:	In years where a contribution is required current ratepayers will bear the burden of an accumulation of years of employee services rather than just the current year employee services. Greater rate volatility and less rate stability as shown in Exhibit A2, Tab 3, Schedule 2.
EGD – Advantage:	Under USGAAP companies are allowed to create an asset or liability to capture the difference between the accrual basis of pension expense and that used for rate making purposes. Therefore there is no specific advantage.
EGD – Disadvantage:	Less comparability to utilities using the accrual basis of expense.

c) There are no other advantages or disadvantages in addition to what has already been filed in Exhibit A2, Tab 3, Schedule 2. Below is a summary of what was filed.

Ratepayer – Advantage:	Current ratepayers will be impacted by current year pension costs. Less rate volatility as evidenced in Exhibit A2, Tab 3, Schedule 2. More transparency and consistency to users of

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

both financial statements for reporting purposes and financial statements for rate making purposes.

Ratepayer – Disadvantage: In years where the plan is in a surplus, ratepayers will still be impacted by the accrual basis expense. However, if the plan does go into a deficit the cash contribution required will be an accumulation of years of employee services rather than just the current year employee services.

EGD – Advantage: Better matching of expenses to the year in which the expense was incurred (service was provided by employees).

More transparency and consistency to users of both financial statements for reporting purposes and financial statements for rate making purposes.

EGD – Disadvantage: None

d)

Ratepayer – Advantage: In years where no contribution is required the current ratepayers would benefit as there would be no expense to be recovered in rates.

Ratepayer – Disadvantage: In years where a contribution is required current ratepayers will bear the burden of an accumulation of years of employee services rather than just the current year employee services.

Less transparency and consistency to users of both financial statements for reporting purposes and financial statements for rate making purposes.

Greater rate volatility and less rate stability as shown in Exhibit A2, Tab 3, Schedule 2.

EGD – Advantage: Better matching of expenses to the year in which the expense was incurred (service was provided

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

by employees).

Under USGAAP companies are allowed to create an asset or liability to capture the difference between the accrual basis of pension expense and that used for rate making purposes. Therefore there is no specific advantage.

EGD – Disadvantage: Less transparency and consistency to users of both financial statements for reporting purposes and financial statements for rate making purposes.

Under USGAAP companies are allowed to create an asset or liability to capture the difference between the accrual basis of pension expense and that used for rate making purposes. Therefore, although Enbridge can get an equivalent to cash basis, there is added administrative burden to maintain two sets of books and reconcile between regulatory financial statements and accounting financial statements.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 2/ Page 2 & 3

EGD did not apply to the Board to switch from the cash to accrual basis for pension for regulatory purposes in 2000 when the CICA Handbook changed. EGD also had the opportunity to apply to the Board to switch to the accrual basis for pension for regulatory purposes in 2009 when the CICA Handbook change impacted rate-regulated companies.

a) Please explain why EGD did not make an application to the Board to switch to the accrual basis for pension for regulatory purposes both in 2000 and 2009.

b) Please provide reasons why the Board should grant EGD's request to switch to the accrual basis for pension for regulatory purposes effective January 1, 2013, in light of the fact that EGD had the opportunity to bring the matter before the Board both in 2000 and 2009.

RESPONSE

Please see the response to Board Staff Interrogatory #11 at Exhibit I, Issue D4, Schedule 1.11.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 2/ Page 2 & 3
Ex. M1/ Tab 1/ Sch 4

Please describe the regulatory tax implications generated from the following, specifically the impact on the regulatory tax provision in the 2013 Test Year, and where this is reflected in EGD's evidence. If the regulatory tax implications are not incorporated into EGD's evidence, please provide updated evidence where necessary.

a) EGD's proposed switch from the cash basis to the accrual basis for pension for regulatory purposes
b) EGD utilizing the cash basis for pension for regulatory purposes
c) EGD utilizing the accrual basis for pension for regulatory purposes

RESPONSE

a) The impact to 2013 regulatory taxes, as a result of switching from the cash basis to the accrual basis for both pension and OPEBs, is that for taxable income determination purposes only the cash amount paid for the year is deductible or expensed whereas accounting income is derived through the expensing of an accrual basis amount.

b) If EGD continued on the cash basis for pension expense, there would be no difference between the amount allowed as an expense for accounting and taxable income determination. EGD cannot continue on the cash basis for OPEBs in 2013.

c) See response to part a).

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

As a result of the timing of the preparation of the 2013 budget, the review of tax impacts from the requested switch to the accrual method for pension and OPEBs was not incorporated within the budget and specifically the budgeting for income taxes. The result is that utility taxable income is overstated by approximately $0.5 million with the deficiency overstated by approximately $0.2 million.

EGD will correct for this item within an Impact Statement #2 to be filed in early August, 2012 the impact of which will result in approximate adjustments to utility income tax, overall revenue requirement and deficiency calculations as stated above.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 2/ Page 2 & 3

a) Please provide the full actuarial valuation report as at December 31, 2009 for pension and the accounting valuation report as at December 31, 2011.
b) Please confirm if EGD's external auditors have audited or reviewed the reports, including the assumptions used. Please provide supporting documentation.

    i. If so, do the reports reflect the auditor's comments?
    ii. If not, when will the external auditor's audit or review take place?

RESPONSE

a) Please see attached.

b) The attached reports were reviewed by the Company's external auditors as part of their year-end audit of Enbridge Gas Distribution's financial statements. Please see attached the audited financial statements for Enbridge Gas Distribution as of December 31, 2011, including the auditor's report which is evidence of their review of the reports.
    i. The auditors do not provide direct comments on the reports but assess the report, including assumptions, for reasonableness as part of their year-end audit.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

September 30, 2010

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

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2009

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Canada Revenue Agency Registration Number: 0242016

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Note to reader regarding actuarial valuations:

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

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

To prepare this report, actuarial assumptions are used to model the results for a single scenario from a range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

Furthermore, should the plan be wound up, the going-concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound-up on the valuation date. Emerging experience, including the growth of wind-up liabilities compared to the plan's assets (including future contributions and investment returns), will affect the wind-up funded position of the plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

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

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1

Introduction

To Enbridge Gas Distribution Inc.

At your request, we have conducted an actuarial valuation of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "Plan"), sponsored by Enbridge Gas Distribution Inc. ("Enbridge"), as at the valuation date, December 31, 2009. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- the funded status of the plan as at December 31, 2009 on going-concern, hypothetical wind-up and solvency bases;
- the minimum required funding contributions from 2010, in accordance with the *Pension Benefits Act (Ontario)* and Enbridge's elections in regards to determining the solvency funding requirements; and
- the maximum permissible funding contributions from 2010, in accordance with the *Income Tax Act*.

The information contained in this report was prepared for the internal use of the Enbridge and for filing with the Financial Services Commission of Ontario ("FSCO") and with the Canada Revenue Agency ("CRA"), in connection with our actuarial valuation of the Plan. This report will be filed with FSCO and with CRA. This report is not intended or suitable for any other purpose.

The next actuarial valuation of the Plan will be required as at a date not later than December 31, 2012, or as at the date of an earlier amendment to the Plan. However, If Enbridge intends to use the funding excess to fund the employer's current service cost, a

cost certificate is required to be filed annually showing that sufficient surplus remains to justify the contribution holiday.

Events Since the Last Valuation

Pension Plan

There have been no special events since the last valuation date.

Effective January 1, 2008, the Plan was amended such that Senior Management Employees ("SMEs") of Enbridge Gas Distribution Inc., Enbridge Gas New Brunswick Inc., Gazifere Inc., Enbridge Solutions Inc., or Enbridge Electric Connections Inc. would begin accruing benefits under the defined benefit component of the Plan, where this was not previously the case. The contribution holiday taken since January 1, 2008 has been in accordance with the cost certificate filed along with the amendment. This amendment increased the going-concern funding target actuarial liabilities as at December 31, 2009 by $2,068,900, and the 2010 employer current service cost by $959,200.

The Plan was also amended to reflect changes in regulations and various housekeeping items. These amendments had no material impact on Plan liabilities or current service costs.

A summary of the Plan provisions is provided in Appendix F.

Assumptions

We have used the same going-concern valuation assumptions and methods as were used for the previous valuation as of December 31, 2006, except for the following:

Assumption	Current valuation	Previous valuation
Discount rate:	6.00%	5.75%
Pensionable earnings increases:	3.50%	5.00%
Mortality:	UP94 with future mortality improvements using Scale AA	UP94 with mortality improvements to 2015

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date.

A summary of the going-concern, and hypothetical wind-up and solvency assumptions are provided in Appendices C and D, respectively.

Regulatory Environment and Actuarial Standards

There have been no changes to the *Pension Benefits Act (Ontario)* (the "Act") and Regulations which impact the funding of the Plan.

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

Subsequent Events

In September 2010, the Enbridge Electric Connections Inc. business was divested and consequently removed as a participating employer in the Plan. Therefore, there are no longer any remaining active members in respect of this participating employer. This sale did not have a material financial impact on the results of this valuation, and as such, the impact has not been reflected in this valuation report.

In December 2009, Bill 236 was introduced as the first step in the Ontario government's plan to reform pension legislation and regulations in response to the recommendations of the Expert Commission on Pensions. In the context of implementation of this reform, Bill 236 was tabled on December 9, 2009 and provides for changes to the Act. The majority of changes will come into force on a date or dates to be fixed by proclamation. This allows implementation on different effective dates and coordination of effective dates with the adoption of related regulations. While a number of these changes are already in effect, none of the changes currently in force have a material financial impact on the results of this valuation, and as such, they have not been reflected in this actuarial valuation report.

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

Impact of Case Law

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

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("*Monsanto*"), thereby upholding the requirements to distribute surplus on partial plan wind-up under the *Pension Benefits Act (Ontario).* The decision has retroactive application and applies on the termination of Ontario employees if they are included in a partial plan wind-up, regardless of the province in which the pension plan is registered.

Although this decision dealt with Ontario legislation, it is possible that it could have application to other provinces since the underlying language in the *Pension Benefits Act*

(Ontario), is similar to language in a number of other provinces, either currently or in the past.

For Federally regulated employees, on March 5, 2009, the Supreme Court of Canada denied leave to appeal in Cousins v. Attorney General of Canada and Marine Atlantic Inc. ("Marine Atlantic") confirming that the *Pension Benefits Standards Act* does not require surplus distribution on a partial plan termination.

On the Telesis partial plan wind-up, surplus was distributed to affected plan members. We are not aware of any other partial plan wind-up having been declared in respect of the plan where the Monsanto decision may apply. In preparing this actuarial valuation, we have therefore assumed that all plan assets are available to cover the plan liabilities presented in this report. The subsequent declaration of a partial wind-up of the plan where *Monsanto* may apply in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on plan assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the regulatory authorities to declare partial wind-ups and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the regulatory authorities might declare a partial wind-up in respect of other events in the plan's history.

2

Defined Contribution Component of the Plan

The Plan is made up of defined contribution ("DC") and defined benefit ("DB") components. The DC component is considered in this Section while Sections 3 to 5 and 7 relate only to the DB component of the Plan, except where required by law.

Reconciliation of DC Assets

	2007	2008	2009
January 1	$5,480,000	$6,749,000	$6,500,000
PLUS			
Members' contributions	$0	$0	$0
Company's contributions	$0	$0	$0
Transfers to DC from DB	$1,270,000	$1,433,000	$1,374,000
Investment returns from all sources, net of expenses	$152,000	($1,525,000)	$1,297,000
	$1,422,000	($92,000)	$2,671,000
LESS			
Refunds	$153,000	$157,000	$334,000
	$153,000	$157,000	$334,000
December 31	$6,749,000	$6,500,000	$8,837,000
Rate of return net of expenses	2.52%	-20.64%	18.48%

Current Service Cost

We have estimated employer DC current service cost for the following year in comparison to the estimate from the previous valuation as follows:

	2010	2007
Employer DC current service cost	$1,364,600	$1,281,000
Employer DC current service cost as a percentage of members' pensionable earnings, excluding pensionable bonuses[1]	5.91%	5.64%

For reference, the Plan terms are summarised in Appendix F.

[1] The DC employer current service cost expressed as a percentage of pensionable earnings, including pensionable bonus, for 2010 and 2007 is 5.49% and 5.25%, respectively.

3

Valuation Results – Going-Concern

Financial Status

A going-concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	13.31.2009	13.31.2006
Assets		
Market value of assets	$698,698,000	$821,214,000
Going-concern funding target		
▪ active members	$297,039,000	$304,819,600
▪ suspended members	$11,350,300	$23,481,300
▪ pensioners and survivors	$326,142,300	$279,001,100
▪ deferred pensioners	$7,003,400	$7,063,600
Total	$641,535,000	$614,365,600
Funding excess (shortfall)	$57,163,000	$206,848,400
Assets over funding targets	109%	133%

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		$206,848,400
Interest on funding excess (funding shortfall) at 5.75% per year		$37,772,400
Employer's special payments, with interest		$0
DB contributions drawn from funding excess, with interest		($47,754,700)
DC contributions drawn from funding excess, with interest		($4,437,400)
Expected funding excess (funding shortfall)		$192,428,700
Net experience gains (losses)		
▪ Net investment return	($179,832,600)	
▪ Increases in pensionable earnings / YMPE / ITA maximum pension limit	$10,798,400	
▪ Indexation	$2,069,100	
▪ Mortality	($2,540,100)	
▪ Retirement	($144,300)	
▪ Termination	($2,805,000)	
Total experience gains (losses)		($172,454,500)
Impact of changes in assumptions and methods		$39,102,500
Impact of amendments		($2,068,900)
Net impact of other elements of gains and losses		$155,200
Funding excess (shortfall) as at current valuation		$57,163,000

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date compared with the corresponding value determined in the previous valuation, is as follows:

		2010	2007
Current service cost of non-SME members		$13,735,800	$14,358,200
Current service cost of SME members		$959,300	$0
Total current service cost		$14,695,100	$14,358,200
Estimated members' required contributions		$0	$0
Estimated employers' current service cost		$14,695,100	$14,358,200
Total base pensionable earnings excluding pensionable bonuses for the year following valuation date - non-SME members		$123,732,000	$104,168,000
Total base pensionable earnings excluding pensionable bonuses for the year following valuation date - SME members		$4,116,000	$0
Total members' pensionable earnings, excluding pensionable bonuses for year following valuation date		$127,848,000	$104,168,000
Employers' current service cost expressed as a percentage of members' pensionable earnings, excluding pensionable bonuses	Non-SMEs	11.10%	13.78%
	SMEs	23.31%	N/A
	Aggregate	11.49%	13.78%

The key factors that have caused a change in the employer's current service cost for non-SME members since the previous valuation are summarized in the following table:

	Non-SMEs
Employer's current service cost as at previous valuation	13.78%
Demographic changes	(0.25%)
Plan amendments	0.00%
Changes in assumptions	(2.43%)
Employer's current service cost as at current valuation	11.10%

4

Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	12.31.2009	12.31.2006
Assets		
Market value of assets	$698,698,000	$821,214,000
Termination expense provision	($2,000,000)	($600,000)
Wind-up assets	$696,698,000	$820,614,000
Present value of accrued benefits for:		
▪ active members	$367,718,200	$302,517,100
▪ suspended members	$12,508,700	$20,713,300
▪ pensioners and survivors	$384,153,400	$309,105,500
▪ deferred pensioners	$8,726,600	$8,540,900
Total wind-up liability	$773,106,900	$640,876,800
Wind-up excess (shortfall)	($76,408,900)	$179,737,200

Impact of Plan Wind-up

In our opinion, the value of the Plan's assets would be less than its actuarial liabilities if the Plan were to be wound up on the valuation date. Specifically, actuarial liabilities would exceed the market value of assets by $76,408,900. This calculation includes a provision for termination expenses expected to be paid from the fund.

5

Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on this basis is determined in a similar manner to the hypothetical wind-up basis, except for the following:

Exceptions	Reflected in valuation based on the Enbridge's directions
The circumstance under which the Plan is assumed to be wound-up could differ for the solvency and hypothetical wind-up valuations.	Same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up.
Certain benefits can be excluded from the solvency financial position. These include: (a) any escalated adjustment (e.g. cost-of-living adjustments), (b) certain plant closure benefits, (c) certain permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	The following benefits were excluded from the solvency liabilities shown in this valuation: ▪ Cost-of-living adjustments have been excluded from the December 31, 2009 solvency liabilities. However, they are included in the December 31, 2006 solvency liabilities.
The financial position on the solvency basis needs to be adjusted for any Prior Year Credit Balance.	Not applicable.

Exceptions	Reflected in valuation based on the Enbridge's directions
The solvency financial position can be determined by smoothing assets and the solvency discount rate over a period of up to 5 years.	Smoothing was not used.
In accordance with actuarial standards, the termination expense provision used for the hypothetical wind-up valuation includes a reduction in the value of the Plan's assets resulting from their liquidation and a provision for the related transaction fees. Since the solvency valuation is based on the market value of assets and not the liquidated value of assets, these adjustments can be excluded from the solvency termination expense provision.	The termination expense provision used in the solvency valuation is $600,000, which differs from the provision of $2,000,000 used in the hypothetical wind-up valuation. The termination provision used for the solvency valuation excludes the provision for the market impact of liquidating the plan assets.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	12.31.2009	12.31.2006
Assets		
Market value of assets	$698,698,000	$821,214,000
Termination expense provision	($600,000)	($600,000)
Net assets	$698,098,000	$820,614,000
Total hypothetical wind-up liabilities	$773,106,900	$640,876,800
Difference in circumstances of assumed wind-up	$0	$0
Value of excluded benefits	($107,030,000)	($0)
Liabilities on a solvency basis	$666,076,900	$640,876,800
Surplus (shortfall) on a market value basis	$32,021,100	$179,737,200
Transfer ratio	0.90	1.28

6

Minimum Funding Requirements

The Act prescribes the minimum contributions that Enbridge must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going-concern current service cost and special payments to fund any going-concern or solvency shortfalls.

There is a funding excess and no special payments are required for solvency purposes on the basis of the assumptions and methods described in this report. Under these circumstances the Act does not require the employer to contribute to the Plan until after the funding excess has been applied towards the employer's current service cost.

If the funding excess is used to fund the employer's current service cost, a cost certificate is required to be filed annually showing that sufficient excess remains to justify the contribution holiday.

Once the funding excess has been so applied, employer contributions must resume. On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer contributions, as well as an estimate of the employer contributions from the valuation date are as follows:

	Employer's contribution rule	Estimated employer's contributions		
Period beginning	Current service cost[2]	Annual current service cost	Funding excess applied	Minimum annual contributions
January 1, 2010	11.49%	$14,695,100	$14,695,100	$0

[2] For current service contributions expresses as a percentage of members' pensionable earnings applicable to each participating employer, see Appendix G – Results by Participating Employer.

The estimated contribution amounts above are based on projected members' pensionable earnings. Therefore, actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions resume in accordance with the Act.

Other Considerations

Differences between valuation bases

Minimum required special payments are based on going-concern and solvency shortfalls, if any. There is no provision in the minimum funding requirements to fund wind-up shortfalls. Since solvency liabilities exclude the plan's indexing provisions, the assets may not be sufficient to pay for all accrued benefits in the event the plan is wound up. If a contribution holiday is taken, then the wind-up shortfall will grow.

In addition, although minimum funding requirements do include a requirement to fund the going-concern current service cost, there is no requirement to fund the expected growth in the wind-up or solvency liability after the valuation date, which is greater than the going-concern current service cost. Therefore, the wind-up deficit will grow even when the going-concern current service cost is being funded.

Timing of contributions

Funding contributions are due on monthly basis. Contributions for current service cost must be made within 30 days following the month to which they apply. Special payment contributions must be made in the month to which they apply.

Retroactive contributions

Enbridge must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Payment of benefits

The *Act* imposes certain restrictions on the payment of lump sums from the Plan when the transfer ratio revealed in an actuarial valuation is less than one. If the transfer ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the *Act* to allow for the full payment of benefits, and otherwise should take the prescribed actions.

However, transfer deficiencies that are less than 5% of the Year's Maximum Pensionable Earnings ("YMPE") under the Canada/Quebec Pension Plan can be paid in full until such time as the sum of all such transfer deficiencies paid since the date of the last actuarial valuation exceed 5% of the market value of the Plan assets at that date, at which time, this exemption no longer applies.

Additional restrictions are imposed when:

- The transfer ratio revealed in the most recently filed actuarial valuation is less than one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined by 10% or more of its previous value since the date the last valuation was filed.

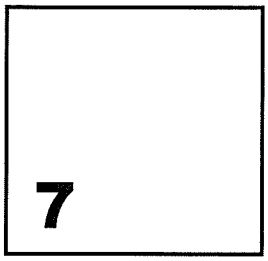
- The transfer ratio revealed in the most recently filed actuarial valuation is greater than or equal to one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined to less than 0.90 since the date the last valuation was filed.

As such, the administrator should monitor the transfer ratio of the Plan and, if necessary, take the prescribed actions.

Contributions to the DC component

In addition to any contribution requirements in respect of the DB component of the Plan, and notwithstanding any prohibition to fund the DB component of the Plan, contributions to the individual member DC accounts should be made in accordance with the Plan terms.

Since the DB component of the Plan is fully funded on both going-concern and solvency bases then, subject to the Act, the Plan terms and any collective or employment agreement, it may be possible for Enbridge to apply DB assets in satisfaction of its contribution requirements for the DC component of the Plan.



Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going-concern or on a wind-up basis the maximum permitted contributions are equal to the employer's current service cost, plus the greater of the going-concern funding shortfall and wind-up shortfall.

For a plan which is fully funded on both going-concern and wind-up bases, the employer can remit a contribution equal to the employer's current service cost, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going-concern and wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going-concern funding excess exceeds 25% of the going-concern funding target (i.e., 25% of $641,535,000, or $160,383,800).

Schedule of Maximum Contributions

Enbridge is permitted to fully fund the greater of the going-concern and wind-up shortfalls; $76,408,900, as well as make current service cost contributions. The portion of this contribution representing the payment of the wind-up shortfall can be increased with interest at 4.34% per year from the valuation date to the date the payment is made, and must be reduced by the amount of any deficit funding made from the valuation date to the date the payment is made.

Assuming Enbridge contributes the wind-up shortfall of $76,408,900 as of the valuation date, the rule for determining the estimated maximum eligible annual contributions, as well as an estimate of the maximum eligible contributions until the next valuation are as follows:

	Employer's contribution rule		Estimated employer's contributions
Year beginning	**Current service cost[3]**	**Deficit Funding**	**Annual current service cost**
January 1, 2010	11.49%	N/A	$14,695,100
January 1, 2011	11.49%	N/A	$15,209,400
January 1, 2012	11.49%	N/A	$15,741,700

The employer's current service cost in the above table was estimated based on projected members' pensionable earnings. The actual employer's current service cost will be different from these estimates and, as such, the contribution requirements should be monitored closely to ensure compliance with the ITA.

Contributions to the DC component

In addition to any contribution requirements in respect of the DB component of the Plan, and notwithstanding any prohibition to fund the DB component of the Plan, contributions to the individual member DC accounts should be made in accordance with the Plan terms.

[3] For current service contributions expresses as a percentage of members' pensionable earnings applicable to each participating employer, see Appendix G – Results by Participating Employer.

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Actuarial Opinion

In our opinion, for the purposes of this valuation,

- the data on which the valuation is based are sufficient and reliable;
- all assumptions were independently reasonable at the time the valuation was prepared and are, in aggregate, appropriate; and,
- the methods employed in the valuation are appropriate.

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

Chris Heller
FCIA, FSA

September 29, 2010
Date

Amy Pun
FCIA, FSA

September 29, 2010
Date

Appendix A

Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result
Transfer Ratio	The ratio of solvency assets to the sum of the solvency liabilities and liabilities for benefits, other than benefits payable under qualifying annuity contracts, that were excluded in calculating the solvency liabilities.	0.90
Prior Year Credit Balance	Accumulated excess of contributions made to the pension plan in excess of the minimum required contributions (note: only applies if Enbridge chooses to treat the excess contributions as a Prior Year Credit Balance).	$0
Solvency Assets	Market value of assets (less provision for estimated termination expenses) including accrued or receivable income and excluding the value of any qualifying annuity contracts.	$698,098,000
Solvency Asset Adjustment	The sum of:	
	(a) the difference between smoothed value of assets and the market value of assets;	$0
	(b) the present value of any going-concern special payments (including those identified in this report) within 5 years following the valuation date;	$0
	(c) the present value of any previously scheduled solvency special payments (excluding those identified in this report)	$0
		$0

Defined Term	Description	Result
Solvency Excess / (Deficiency)	The amount by which the sum of:	
	(a) the solvency liabilities	$666,076,900
	(b) the solvency liability adjustment	$0
	(c) the prior year credit balance	$0
		$666,076,900
	Exceed the sum of	
	(d) the solvency assets	$698,098,000
	(e) the solvency asset adjustment	$0
		$698,098,000
		$32,021,100
Solvency Liabilities	Liabilities determined as if the plan had been wound up on the valuation date, including liabilities for plant closure benefits or permanent layoff benefits that would be immediately payable if the employer's business were discontinued on the valuation date of the report, but excluding liabilities for, (a) any escalated adjustment, (b) excluded plant closure benefits, (c) excluded permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	$666,076,900
Solvency Liability Adjustment	The amount by which solvency liabilities are adjusted as a result of using a solvency valuation interest rate that is the average of market interest rates calculated over the period of time used in the determination of the smoothed value of assets.	$0

Timing of Next Required Valuation

In accordance with the Act the next valuation of the Plan would be required at an effective date within one year of the current valuation date if:

- The ratio of solvency assets to solvency liabilities is less than 80%; or
- The ratio of solvency assets to solvency liabilities is less than 90% and solvency liabilities exceed solvency assets by $5 million or more.

Otherwise, the next valuation of the Plan would be required at an effective date no later than three years after the current valuation date.

Accordingly, the next valuation of the Plan will be required as of December 31, 2012.

However, If Enbridge intends to use the funding excess to fund the employer's current service cost, a cost certificate is required to be filed annually showing that sufficient excess remains to justify the contribution holiday.

Special Payments

As the Plan does not have a going-concern deficit or a solvency deficit, no special payments are required.

Pension Benefit Guarantee Fund (PBGF) Assessment

The PBGF assessment is calculated as follows:

$1 for each Ontario member (since there is a solvency excess)	$3,500
PBGF assessment	$3,500

Prior Year Credit Balance

The Prior Year Credit Balance was determined as follows:

Prior Year Credit Balance at previous valuation	$0	(a)
Actual employer contributions	$0	(b)
Required employer contributions	$0	(c)
Prior Year Credit Balance at current valuation	$0	(d) = (a) + (b) - (c)

Appendix B

Plan Assets

The DB assets of the Plan are held in trust by CIBC Mellon. The DC assets of the Plan are held by the Standard Life Assurance Company of Canada. In preparing this report, we have relied upon the draft audited financial statements provided by Enbridge.

Reconciliation of Market Value of Plan Assets

The DB fund transactions since the last valuation are summarized in the following table:

	2007	2008	2009
January 1	$821,214,000	$802,284,000	$628,233,000
PLUS			
Company's contributions			
▪ Current service	$0	$0	$0
▪ Special payments	$0	$0	$0
Investment income	$11,608,000	($139,131,000)	$106,052,000
	$11,608,000	($139,131,000)	$106,052,000
LESS			
Pensions paid	$24,428,000	$25,673,000	$27,516,000
Lump-sum refunds	$1,143,000	$1,966,000	$2,934,000
Transfer to DC	$1,270,000	$1,433,000	$1,374,000
Investment expenses	$2,117,000	$4,168,000	$2,112,000
Other expenses	$1,580,000	$1,680,000	$1,651,000
	$30,538,000	$34,920,000	$35,587,000
December 31	$802,284,000	$628,233,000	$698,698,000
Gross rate of return	1.44%	-17.73%	17.37%
Rate of return net of expenses	0.98%	-18.40%	16.71%

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

Investment Policy

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

The constraints on the DB component asset mix and the actual asset mix at the valuation date are provided for information purposes:

	DB Investment Policy			Actual Asset Mix
	Minimum	**Target**	**Maximum**	**as at December 31, 2009**
Canadian equities	18.0%	21.0%	24.0%	22.4%
Foreign equities	22.5%	31.5%	40.5%	31.1%
Fixed income – universe	19.5%	32.5%	35.5%	30.9%
Fixed Income – real return	7.0%	10.0%	13.0%	10.0%
Infrastructure	2.0%	5.0%	8.0%	5.3%
Cash and short term assets	0.0%	0.0%	5.0%	0.3%
		100%		100%

Appendix C

Methods and Assumptions – Going-concern

Valuation of Assets

For this valuation, we have used the market value of assets.

Valuation of Going-concern Funding Target

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

For purposes of the going-concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the going-concern funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to meet the plan's cash flow requirements.

As required under the Act, a funding shortfall will be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial funding method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial funding method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

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

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

Actuarial Assumptions – Going-concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	6.00%	5.75%
Inflation:	2.50%	2.50%
ITA limit / YMPE increases:	3.00%	3.00%
Pensionable earnings increases:	3.50%	5.00%
Post retirement pension increases:	1.25%	1.25%
Retirement rates:	Age related table	Age related table
Termination rates:	Age related table	Age related table
Mortality rates:	100% of the rates of the 1994 Uninsured Pensioner Mortality Table	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using Scale AA	Static projection to 2015 using Scale AA
Disability rates:	None	None
Eligible spouse at retirement:	80%	80%
Spousal age difference:	Male 2 years older	Male 2 years older
DB/DC choice:	Continue in current component	Continue in current component

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken the rate of pay on December 31, 2009 and assumed that such pensionable earnings will increase at the assumed rate on April 1st each year.

Pensionable Bonuses

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

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

Age Related Tables

Sample rates from the age related tables are summarized below:

Age	Termination - Male	Termination - Female	Retirement
20	5.0%	9.5%	0.0%
25	5.0%	13.0%	0.0%
30	5.0%	11.0%	0.0%
35	4.6%	8.5%	0.0%
40	3.0%	4.0%	0.0%
45	2.5%	3.9%	0.0%
50	1.5%	2.8%	0.0%
55	0.0%	0.0%	5.0%
56	0.0%	0.0%	5.0%
57	0.0%	0.0%	7.5%
58	0.0%	0.0%	7.5%
59	0.0%	0.0%	10.0%
60	0.0%	0.0%	20.0%
61	0.0%	0.0%	20.0%
62	0.0%	0.0%	20.0%
63	0.0%	0.0%	20.0%
64	0.0%	0.0%	20.0%
65	0.0%	0.0%	100.0%

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

For members who terminate from the Plan before being eligible to retire we have assumed two-thirds will elect a commuted value determined on a basis consistent with the 2009 CIA Standard, and that one-third will elect a deferred, with pension commencement at age 55.

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- Additional returns assumed to be achievable due to active equity management (net of related expenses).
- Implicit provision for expenses determined as the expected rate of investment and administrative expenses to be paid from the fund in the future.
- A margin for adverse deviations, based on the proportion of the Plan assets invested in equities and the excess return expected on equities, over government bond yields.

The discount was developed as follows:

Assumed investment return	7.41%
Active management	0.29%
Implicit expense provision	(0.50%)
Margin	(1.20%)
Net discount rate	6.00%

Inflation

The inflation assumption is based on the midpoint of the Bank of Canada's inflation target range of between 1% and 3%, and market expectations of long-term inflation implied by the yields on annual and real return bonds on the valuation date of 2.7%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

This assumption is based on Company expectations.

Post retirement pension increases

The assumption is based on the Plan formula and inflation assumption above.

Retirement rates

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

Termination rates

Due to the size of the Plan, there is no meaningful termination experience. The assumption is based on an industry table that is consistent with our experience with similar plans and employee groups. Recent experience has been consistent with this assumption.

Mortality rates

Due to the size of the Plan, there is no meaningful mortality experience but there is no reason to expect the mortality to differ from the 1994 Uninsured Pensioners mortality table. Furthermore, there is strong evidence of continuing improvement in mortality since 1994 and it has become an industry standard to assume this trend continues into the future. We have used the AA projection scale to allow for improvements in mortality since 1994, and indefinitely in the future.

Based on to the assumption used, the life expectancy of a member age 65 at the valuation date is 19.5 years for males and 22.0 years for females.

Recent experience has been consistent with this assumption.

Disability rates

Such an assumption would not have a material impact on the valuation.

Eligible spouse

The assumption is based on the proportion of active members with a spouse that are within 5 years of being eligible for retirement (actual status used for retirees).

Spousal age difference

The assumption is based on recent Plan experience showing males are typically 2 years older than their spouse.

Defined Benefit / Defined Contribution choice

The current service cost depends on the members' participation in the defined benefit or defined contribution component of the Plan. Since contributions are made as a percentage of pensionable earnings they automatically adjust when members change provisions.

Appendix D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound-up on the effective date of the valuation. For the purposes of the hypothetical wind-up valuation, the Plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on the valuation date, with all members fully vested in their accrued benefits.

The circumstances in which the Plan wind-up is assumed to have taken place are as follows:

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

Thereby giving rise to the following benefits:

- Active and suspended members not within 10 years of pensionable age (under the age of 55) receive the termination benefit under the Plan;
- Active and suspended members within 10 years of pensionable age (age 55 and older) receive the retirement benefit under the Plan; and

- Deferred pensioners, pensioners and survivors receive the benefit to which they are entitled on the valuation date.

No benefits payable on Plan wind-up were excluded from our calculations.

Upon Plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3800 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2009 for benefits expected to be settled through a lump sum transfer in accordance with relevant portability requirements.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities. However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. Therefore, we have relied upon the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2009 and December 30, 2010.*

We have not included a provision for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of benefit settlement elected by member	
Lump sum:	70% of active members under age 55 and 40% of active members over age 55 elect to receive their benefit entitlement in a lump sum
Annuity purchase:	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuity
Basis for benefits assumed to be settled through a lump sum	
Mortality rates:	UP94 projected to 2020
Non-indexed interest rate:	3.90% per year for 10 years, 5.40% per year thereafter
Partially-indexed (50%) interest rate:	3.00% per year for 10 years, 4.10% per year thereafter
Partially-indexed (55%) interest rate:	2.90% per year for 10 years, 3.90% per year thereafter
Maximum pension limit:	▪ $2,494.44 per year of service for members over age 55 ▪ $2,494.44 per year of service, projected forward to the age which maximizes value at 2.73% for 10 years, and 3.59% thereafter, for members under age 55
Basis for benefits assumed to be settled through the purchase of an annuity	
Mortality rates:	UP94 projected to 2020
Non-indexed interest rate:	4.49% per year
Partially-indexed (50%) interest rate:	2.99% per year
Partially-indexed (55%) interest rate:	2.83% per year
Maximum pension limit:	▪ $2,494.44 per year of service for immediate annuities ▪ $2,494.44 per year of service, projected forward to the age which maximizes value at 3.92% per year for deferred annuities
Retirement age	
Maximum value:	Members are assumed to retire at the age which maximizes their value from the Plan based on the plan eligibility requirements which have been met at the valuation date
Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equal 55 at the valuation date, reflect their entitlement to grow into early retirement subsidies and indexation benefits
Other assumptions	
Special payments:	Discounted at the average interest rate of 4.34% per year
Final average earnings:	Based on actual pensionable earnings and pensionable bonuses over the averaging period
Family composition:	Same as for going-concern valuation
Termination expenses:	$2,000,000

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

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the Plan's assets and for the reduction in the value of the Plan's equity assets resulting from their liquidation. Such fees and liquidation impact are difficult to assess and will vary depending on the nature of the assets held and market conditions at the time assets are liquidated.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested. Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

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

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

Solvency Basis

To determine the solvency liability, we have valued those benefits that would have been paid had the Plan been wound-up on the valuation date, with the exception of certain benefits which may be excluded, as permitted by the Act. Specifically, future cost-of-living increases on pensions in payment were excluded from our calculation of solvency liabilities. All members are assumed to be fully vested in their accrued benefits.

In addition, the estimated termination expense provision for determining the solvency financial position of the Plan is $600,000 (versus $2,000,000 used for the hypothetical wind-up basis). This amount excludes the provision for transaction fees and market input related to liquidating the Plan's assets.

The solvency position is determined in accordance with the requirements of the Act.

Appendix E

Membership Data

The actuarial valuation is based on membership data as at December 31, 2009, provided by Enbridge.

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

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

Membership Data

	12.31.2009	12.31.2006
Active and Disabled Members Accruing Defined Benefit Service (Non-SMEs)		
Number	1,736	1,685
Total base earnings at the valuation date	$124,024,000	$104,168,000
Average base earnings at the valuation date	$71,400	$61,800
Average years of Non-SME DB pensionable service	13.7 years	14.1 years
Average age	46.3 years	46.1 years
Active and Disabled Members Accruing Defined Benefit Service (SMEs)		
Number	33	N/A
Total base earnings at the valuation date	$6,148,000	N/A
Average base earnings at the valuation date	$186,300	N/A
Average years of Non-SME DB pensionable service	12.5 years	N/A
Average years of SME DB pensionable service	1.9 years	N/A
Average age	49.9 years	N/A
Suspended Defined Benefit Members Accruing Defined Contribution Service		
Number	98	138
Total base earnings at the valuation date	$8,010,000	$10,026,900
Average base earnings at the valuation date	$81,700	$72,700
Average years of Non-SME DB pensionable service	5.4 years	5.8 years
Average years of DC pensionable service	16.0 years	13.5 years
Average age	43.8 years	41.4 years
Other Suspended Defined Benefit Members (Non-SMEs)		
Number	24	44
Total base earnings at the valuation date	$4,836,000	$6,928,000
Average base earnings at the valuation date	$201,500	$157,500
Average years of Non-SME DB pensionable service	7.4 years	10.9 years
Average age	46.6 years	48.0 years

Membership Data (cont'd)

	12.31.2009	12.31.2006
Active Defined Contribution Members without Defined Benefit Service		
Number	200	190
Total base earnings at the valuation date	$15,438,000	$12,673,000
Average base earnings at the valuation date	$77,200	$66,700
Average years of DC pensionable service	4.8 years	3.2 years
Average age	40.6 years	36.9 years
Suspended Defined Contribution Members without Defined Benefit Service		
Number	9	7
Total base earnings at the valuation date	$1,080,000	$519,000
Average base earnings at the valuation date	$120,000	$74,100
Average years of DC pensionable service	7.1 years	5.9 years
Average age	36.5 years	34.6 years
Deferred Pensioners		
Number	185	164
Total annual pension*	$900,300	$797,000
Average annual pension*	$4,900	$4,900
Average age	49.3 years	48.3 years
Pensioners and Survivors		
Number	1,368	1,277
Total annual lifetime pension	$26,264,000	$22,110,000
Average annual lifetime pension	$19,200	$17,300
Total annual temporary pension	$1,667,000	$1,562,000
Average age	72.0 years	71.6 years

* For the December 31, 2006 valuation, the annual pension shown is payable at age 55. For the December 31, 2009 valuation, the annual pension shown is payable at age 65.

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

Reconciliation of Membership

	Active and Disabled Members Accruing DB Service	Suspended DB Members	Active DC Members (without DB service)	Deferred Pensioners	Pensioners and Survivors	Total
Number at January 1, 2009	**1,685**	**182**	**197**	**164**	**1,277**	**3,505**
Adjustment	-	-	-	3	(1)	2
New entrants	322	-	89	-	-	411
Transfers						
▪ Transfers from DC to SME	4	-	(4)	-	-	-
▪ Transfers from DB to DC	(3)	3	-	-	-	-
▪ Transfers from DC to DB	50	(29)	(21)	-	-	-
▪ SME transfer West to East	1	(1)	-	-	-	-
▪ SME transfer East to West	(4)	4	-	-	-	-
▪ Net to suspended status	19	(19)	-	-	-	-
Retirements						
▪ DB Retirements	(168)	(5)	-	(9)	182	-
▪ DC Retirements	-	-	(2)	-	-	(2)
Terminations of employment						
▪ Refunds & lump sum payments	(56)	(8)	(35)	(19)	-	(118)
▪ Deferred pensions	(20)	(5)	-	25	-	-
▪ Non-vested	(33)	-	(15)	-	-	(48)
▪ Terminations not yet elected	(21)	-	-	21	-	-
Deaths						
▪ With further entitlement	(4)	-	-	-	(38)	(42)
▪ With no further entitlement	(3)	-	-	-	(93)	(96)
▪ New survivors	-	-	-	-	42	42
Guarantee expired	-	-	-	-	(1)	(1)
Marital Breakdown	-	-	-	-	-	-
Number at December 31, 2009	**1,769**	**122***	**209****	**185**	**1,368**	**3,653**

* Of these 122 members, 98 are accruing benefits in the DC component of the plan.

** Of these 209 members, 200 are accruing benefits in the DC component of the plan.

The distribution of the active and disabled members by age and service as at December 31, 2009, is summarized as follows:

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

	Years of Defined Benefit Pensionable Service as at December 31, 2009								
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**32-34**	**35+**	**Total**
Under 20									
20 - 24	20 $51,685								20 $51,685
25 - 29	129 $60,262	1 *							130 $60,386
30 - 34	120 $64,064	18 $70,580	1 *						139 $64,866
35 - 39	114 $68,004	24 $78,840	22 $77,534	7 $81,940					167 $71,401
40 - 44	123 $69,843	28 $73,405	28 $84,840	50 $75,254	12 $72,667				241 $73,263
45 - 49	66 $71,103	33 $70,961	27 $74,454	72 $70,767	63 $77,397				261 $72,858
50 - 54	60 $70,304	24 $81,659	27 $74,592	55 $71,357	43 $75,946	132 $77,883			341 $75,258
55 - 59	29 $64,064	14 $83,286	14 $74,739	40 $70,913	21 $80,900	74 $74,145	101 $77,645		293 $74,862
60 - 64	10 $45,969	3 $57,284	7 $68,546	30 $70,083	12 $66,899	21 $68,247	23 $66,248	18 $72,599	124 $67,682
65 +	1 *	4 $115,490	2 *	3 $83,791		6 $57,616	2 *	2 *	20 $73,919
Total	**672** **$65,813**	**149** **$76,481**	**128** **$76,595**	**257** **$72,160**	**151** **$76,261**	**233** **$75,305**	**126** **$75,371**	**20** **$71,756**	**1,736** **$71,408**

Total base earnings: $124,024,000

Average age: 46.3 years

Average years of pensionable service: 13.7 years

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

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

	Years of Defined Benefit Pensionable Service as at December 31, 2009							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30+**	**Total**
Under 20								
20 - 24								
25 - 29								
30 - 34								
35 - 39	1 *							1 *
40 - 44	1 *	3 $167,509		1 *				5 $163,784
45 - 49	3 $175,902	3 $174,832	1 *	1 *				8 $184,525
50 - 54	3 $189,320	1 *	2 *	3 $192,193	3 $166,143	1 *		13 $190,232
55 - 59	1 *		2 *		1 *			4 $208,811
60 - 64					1 *			1 *
65 +			1 *					1 *
Total	**9** **$179,364**	**7** **$192,899**	**6** **$200,413**	**5** **$182,384**	**5** **$182,531**	**1** *		**33** **$186,302**

Total base earnings: $6,148,000

Average age: 49.9 years

Average years of pensionable service: 10.6 years

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

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

	Years of Continuous Service as at December 31, 2009							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30+**	**Total**
Under 20								
20 - 24	4 $54,255							4 $54,255
25 - 29	27 $64,724	10 $61,531						37 $63,861
30 - 34	14 $64,083	16 $81,473	1 *					31 $73,717
35 - 39	18 $77,001	11 $84,072	18 $78,374	4 $82,214				51 $79,420
40 - 44	15 $84,307	14 $93,250	12 $96,776	21 $89,409	4 $73,863			66 $89,461
45 - 49	16 $79,886	13 $84,594	8 $91,269	9 $65,919	7 $68,609	2 *		55 $78,526
50 - 54	7 $80,798	5 $67,891	4 $103,403	5 $79,233	1 *	1 *		23 $81,676
55 - 59	5 $74,170	4 $72,246	3 $116,254	1 *	1 *			14 $80,288
60 - 64	6 $72,260	4 $82,065	1 *					11 $80,428
65 +	6 $70,360							6 $70,360
Total	**118** **$72,735**	**77** **$80,592**	**47** **$90,893**	**40** **$81,103**	**13** **$72,545**	**3** **$66,958**		**298** **$78,686**

Total base earnings: $23,448,000

Average age: 41.6 years

Average years of continuous service: 8.5 years

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

Distribution of Inactive Members
By Age Group

	Deferred Pensioners		Pensioners and Survivors	
Age	**Number**	**Average Annual Pension**	**Number**	**Average Annual Pension (including bridge benefits)**
20 - 24				
25 - 29	2	*		
30 - 34	13	$1,315		
35 - 39	20	$2,450	1	*
40 - 44	28	$4,164	1	*
45 - 49	45	$6,057	1	*
50 - 54	33	$6,988	2	*
55 - 59	24	$5,538	113	$25,043
60 - 64	12	$5,880	220	$23,301
65 - 69			259	$21,967
70 - 74			249	$20,235
75 - 79	2	*	236	$16,430
80 - 84			172	$14,060
85 - 89	4	$498	85	$11,734
90 - 94	2	*	21	$9,782
95+			8	$8,493
Total	**185**	**$4,866**	**1,368**	**$19,199**

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

Appendix F

Summary of Plan Provisions

This valuation is based on the plan provisions in effect on December 31, 2009. Since the previous valuation, the Plan was amended such that Senior Management Employees ("SMEs") of Enbridge Gas Distribution Inc., Enbridge Gas New Brunswick Inc., Gazifere Inc., Enbridge Solutions Inc., or Enbridge Electric Connections Inc. would begin accruing benefits under the defined benefit component of the Plan, where this was not previously the case. The Plan was also amended to reflect changes in regulations and various housekeeping items.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on December 31, 2009. This summary is not intended as a complete description of the Plan.

Background	The Plan became effective January 1, 1971 Benefits are based on a set formula and are entirely paid for by Enbridge. Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued Contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service. In the future, members who are not SMEs may switch between the DB and DC components on the January 1 following the date they achieve 40 points or 60 points. Any changes will affect service after the decision point only. Members who are SMEs must participate in the DB component of the Plan.
Eligibility for membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.

Vesting	With the exception of SMEs, all employees are vested after 24 months of continuous service. SMEs are vested immediately upon entering the Plan.
Employee Contributions	No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required.
Retirement Dates	Normal Retirement Date ▪ The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date ▪ A member becomes immediately vested and may choose to retire as early as age 55.
Normal Retirement Pension	**Contributory Service:** 2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service; less 100% of the Contributory Canada Pension Plan Entitlement; **Non-Contributory Service:** 1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service; less 50% of the Non-Contributory Canada Pension Plan Entitlement; **SME Credited Service:** 2.0% of Final Three Year Average Earnings multiplied by years of SME credited service;
Final Five Year Average Earnings	Final Five Year Average Earnings is calculated using the highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees.
Final Three Year Average Earnings	Final Three Year Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by 3.

Canada Pension Plan Entitlement	**Contributory Service:** One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the 5 calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years. **Non-Contributory Service:** Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing the permitted dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%.
Early Retirement Pension	The following benefits apply if a member retires early with the company's consent: ▪ If the member has attained age 60, the pension payable is as described above in the Normal Retirement section. ▪ If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement. ▪ If the member has not attained age 60 the member is also eligible, for non-contributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement. ▪ If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions. If a member retires without company consent the benefit is actuarially equivalent to the benefit payable at age 65.
Maximum Pension	The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of: ▪ 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and ▪ $2,494.44, or such other maximum as may apply from time to time indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the *Income Tax Act* rules.

Indexation of Pensions in Payment	On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership. Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis.
Death benefits	**Death Before Eligible for Early Retirement** If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service. **Death After Eligibility for Early Retirement** If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service. **Death After Retirement** The death benefit payable is in accordance with the form elected. The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members. Other optional forms are available on an actuarially equivalent basis.
Termination Benefits	If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP.
Disability Benefits	Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled.

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on December 31, 2009. This summary is not intended as a complete description of the Plan.

Background	The DC component of the Plan became effective July 1, 2001. Employer contributions are remitted to individual member accounts and are credited with interest. Members receive the balance of their individual employer account upon termination, death or retirement.
Eligibility for membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.
Vesting	All members of the DC component vest after 24 months of continuous service.
Employee contributions	No employee contributions are required or permitted.
Employer contributions	Employer contributions to the DC component are based on a member's points. ▪ less than 40 points: 4.0% of pensionable earnings[4] ▪ 40 to 60 points: 5.5% of pensionable earnings ▪ greater than 60 points: 7.0% of pensionable earnings
Maximum contribution	The employer contributions are limited to the amounts under the *Income Tax Act*.
Pensionable earnings	Base salary plus 50% of actual bonus received.

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

Appendix G

Results by Participating Employer

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

As of December 31, 2009 and at each subsequent valuation, assets are transferred between participating employers in respect of members that transfer between employers. The amount of assets transferred is equal to the amount of going-concern liabilities accrued by the member at the transfer date, adjusted by a proportional share of surplus.

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

Financial Position on a Going-Concern Basis

The results of the valuation of the defined benefit component as at December 31, 2009 partitioned by participating employer and reflecting December 31, 2009 intraplan asset transfers, are summarized as follows:

Financial Position – Going-Concern Basis

	Market Value of Assets[5]	Going-Concern Funding Target	Funding Excess (Shortfall)
Enbridge Gas Distribution Inc.	$679,001,900	$622,478,900	$56,523,000
Enbridge Gas New Brunswick Inc.	$5,896,200	$6,123,300	($227,100)
Enbridge Electric Connections Inc.	$2,263,400	$2,022,500	$240,900
Gazifere Inc.	$10,026,600	$9,498,900	$527,700
Enbridge Solutions Inc.	$1,509,900	$1,411,400	$98,500
Total	$698,698,000	$641,535,000	$57,163,000

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

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

[5] Reflecting December 31, 2009 intraplan transfers.

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members accruing defined benefit or defined contribution service during 2010 partitioned by participating employer is summarized below:

Employers' Current Service Cost

	Defined Benefit Component		Defined Contribution Component	Total
	Estimated current service cost	As a % of pensionable earnings (excluding pensionable bonuses)	Estimated current service cost	
Enbridge Gas Distribution Inc.	$13,658,400	11.69%	$1,215,700	$14,874,100
Enbridge Gas New Brunswick Inc.	$498,700	8.86%	$3,900	$502,600
Enbridge Electric Connections Inc.	$187,500	11.28%	$10,800	$198,300
Gazifere Inc.	$327,800	9.90%	$86,400	$414,200
Enbridge Solutions Inc.	$22,700	5.90%	$47,800	$70,500
Total	$14,695,100	11.49%	$1,364,600	$16,059,700

Headcount by Participating Employer

The membership count as at December 31, 2009 partitioned by participating employer is summarized below:

Headcount by Participating Employer

	Active DB Members	Suspended DB Members	Active DC Members (without DB Service)	Deferred Pensioners	Pensioners and Survivors	Total
Enbridge Gas Distribution Inc.	1,593	116	168	169	1,342	3,388
Enbridge Gas New Brunswick Inc.	98	1	26	10	9	144
Enbridge Electric Connections Inc.	19	-	3	2	-	24
Gazifere Inc.	54	3	8	2	16	83
Enbridge Solutions Inc.	5	2	4	2	1	14
Number at December 31, 2009	**1,769**	**122**	**209**	**185**	**1,368**	**3,653**

Appendix H

Employer Certification

With respect to the report on the actuarial valuation of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, as at December 31, 2009, I hereby certify that, to the best of my knowledge and belief:

- the valuation reflects Enbridge's decisions in regards to determining the solvency funding requirements;
- a copy of the official plan documents and of all amendments made up to December 31, 2009, were provided to the actuary and is reflected appropriately in the summary of plan provision contained herein;
- the asset information summarised in Appendix B is reflective of the Plan's assets;
- the membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2009, and
- all events subsequent to December 31, 2009 that may have an impact on the pension plan have been communicated to the actuary.

09/09/2010
Date

Signed
RON L. SAWATZKY
Name

Appendix I

Actuarial Information Summary

Canada Revenue Agency / Agence du revenu du Canada

ACTUARIAL INFORMATION SUMMARY

Please see the instructions for completing this form. If an item does not apply, enter "N/A".

Part I – Plan Information and Contributions

A. 001. Name of registered pension plan

The Pension Plan for Employees of Enbridge Gas Distribution

B. 002. Registration number

Canada Revenue Agency: 242016 **Other:**

C. 003. Is this plan a designated plan? ☐ Yes ☑ No

D. 004. Valuation date of report YYYY 2009 MM 12 DD 31

E. 005. End date of period covered by report YYYY 2012 MM 12 DD 31

F. 006. Purpose of the report (indicate the reason(s) for which the report was prepared)

☐ Initial report for a newly established plan ☑ Regular (triennial or annual) report for an ongoing plan ☐ Interim report in respect of an amendment to an ongoing plan ☐ Partial Termination

☐ Termination ☐ Conversion ☐ Other (please explain) _____

G. Contributions (prior to application of any credits and/or surplus) for covered period

Periods (see instructions)	Period 1	Period 2	Period 3	Period 4
007. Period start date	YYYY 2010 MM 01 DD 01	YYYY 2011 MM 01 DD 01	YYYY 2012 MM 01 DD 01	YYYY MM DD
008. Period end date	YYYY 2010 MM 12 DD 31	YYYY 2011 MM 12 DD 31	YYYY 2012 MM 12 DD 31	YYYY MM DD
Normal cost (defined benefit provision) 009. Members	0	0	0	
010. Employer	14,695,100	15,209,400	15,741,700	
010a. Explicit expense allowance included in employer normal cost above	0	0	0	
Normal cost (money purchase provision) 011. Members	0	0	0	
012. Employer	1,364,600	1,412,400	1,461,800	
Special payments 013. Special payments for going-concern unfunded liability and/or solvency deficiency	0	0	0	
Fixed contributions 014. Estimated dollar amounts of fixed employer and, if applicable, member contributions (defined benefit provision)	0	0	0	
014a. Estimated dollar amounts of fixed employer and, if applicable, member contributions (money purchase provision)	0	0	0	

Part II – Membership and Actuarial Information

H. Membership information

	Number	Average Age	Average Pensionable Service	Average Salary	Average Annual Pension
015. Active members	1,769	46.40	13.71	72,394	
016. Retired members	1,368	72.00	N/A	N/A	19,200
017. Other participants	307	47.30	N/A	N/A	4,900

I. Actuarial basis for going-concern valuation (see instructions)

020. Asset valuation method

☑ Market ☐ Smoothed Market ☐ Book ☐ Book & Market combination ☐ Other

021. Liability valuation method

☑ Accrued benefit (unit credit) ☐ Entry age normal ☐ Individual level premium ☐ Aggregate

☐ Other (specify) _____

I. Actuarial basis for going-concern valuation (cont'd)

Selected actuarial assumptions

Where a flat rate is used, enter the rate under "Ultimate rate" and "N/A" under "Initial rate" and "Number of years*"

	Initial rate	Number of years*	Ultimate rate
Valuation interest rate			
025. active members	%		6.00 %
026. retired members	%		6.00 %
027. Rate of indexation	%		1.25 %
028. Rate of general wage and salary increase	%		3.50 %
029. YMPE escalation rate	%		3.00 %
030. *Income Tax Regulations'* maximum pension limit escalation	%		3.00 %
031. Rate of CPI increase	%		2.50 %

* from valuation date before ultimate rate becomes effective

035. Year *Income Tax Regulations'* maximum pension limit escalation commences 2011

036. Mortality table

☐ 1994 GAM Static ☐ 1994 Group Annuity Reserving (GAR) ☑ 1994 UP

☐ 80% of 1983 GAM ☐ Other (specify) _____

036a. Generational Mortality Table
Has an assumption of generational mortality improvements been made? ☑ Yes ☐ No

036b. Projected Mortality Table
Has a projection of mortality improvements been made? ☐ Yes ☑ No

036b.(i) If "Yes", what is the year to which the mortality improvements have been projected (see instructions)? YYYY

037. Allowance for promotion, seniority and merit increases

☑ Included in (line **028.**) above ☐ Separate scale based on age or service ☐ No allowance

038. Allowance for expenses

038a. Allowance for investment expenses

☑ Implicit ☐ Explicit

038b. Allowance for administrative expenses

☑ Implicit ☐ Explicit

039. If a multi-employer plan, number of hours of work per member per plan year .....

040. Was a withdrawal scale used? ☑ Yes ☐ No

041. Were variable retirement rates used? ☑ Yes ☐ No

042. If "No", what is the assumed retirement age? .....

J. Actuarial basis for solvency valuation

	Initial rate	Select period	Ultimate rate
Valuation interest rate			
045. active members (electing a lump sum option)	3.90 %	10	5.40 %
046. active members (electing an annuity option)	%		4.49 %
047. retired members	%		4.49 %
048. Rate of indexation	0.87 %	10	1.30 %

049. Mortality table ☑ 1994 UP ☐ Other (specify) _____

049a. Year of projection (see instructions) YYYY 2010

K. Balance sheet information (DB provisions, see instructions)

050. Market value of assets, adjusted for receivables and payables 698,698,000

051. Amount of contributions receivable included in market value above 0

Going-concern valuation

052. Going-concern assets 698,698,000

053. Optional ancillary contributions account balance included in going-concern assets above for a flexible pension plan (if applicable) .....

Going-concern liabilities

060. for active members 297,039,000

061. for retired members 326,142,300

062. for other participants 18,353,700

063. for optional ancillary benefits to be provided under a flexible pension plan (if applicable) 0

064. other reserve 0

K. Balance sheet information (DB provisions, see instructions) (cont'd)

070. Net funded position – surplus/deficit	57,163,000
071. Additional voluntary contributions	
072. Money purchase assets (if applicable)	8,837,000

Solvency Valuation

Complete lines **080.** to **100.** only if the report contains an explicit solvency valuation

Solvency Assets

080. solvency assets with adjustment for expense provision, if any	698,098,000
081. amount of wind-up expense provision reflected in line **080**	600,000
082. optional ancillary contributions account balance included in solvency assets above for a flexible pension plan (if applicable)	0

Solvency Liabilities

090. for active members	315,554,000
091. for retired members	331,179,100
092. for other participants	19,343,800
093. for optional ancillary benefits to be provided under a flexible pension plan (if applicable)	0
094. other reserve	0
100. Net solvency position – surplus/deficit	32,021,100

If the plan provides benefit increases coming into effect during the period covered by the report but after the valuation date, have those increases been reflected in:

102. the going-concern liabilities in lines **060.** to **064.**?	☑ N/A	☐ Yes	☐ No
103. the solvency liabilities in lines **090.** to **094.**?	☑ N/A	☐ Yes	☐ No

L. Actuarial gains/losses

110. Was a gain or loss analysis done?	☑ Yes	☐ No
111. If line **110.** is "Yes", indicate the date of the last filed funding Valuation report and the Net funded position as at that date (YYYY MM DD: 2006 12 31)		206,848,400

If line **110.** is "Yes", indicate amount of gain or loss due to:

112. interest on surplus (unfunded liability)	37,772,400
113. special payments made	0
114. amounts used for contribution holiday	-52,192,100
115. change in actuarial assumptions	39,102,500
116. change in the asset valuation method	0
117. change in liability valuation method	0
118. plan amendments/changes	-2,068,900
119. investment experience	-179,832,600
120. retirement experience	-144,300
121. mortality experience	-2,540,100
122. withdrawal experience	-2,805,000
123. salary increase experience	10,798,400
124. optional ancillary contributions forfeited	0

Major contributing sources other than lines **112.** to **124.** above (specify)

125. Indexing	2,069,100
126.	
127. all other sources (combined)	155,200

M. Subsequent events

135. Are there any subsequent event(s) that have not been reflected in the valuation? (Refer to the SOP)	☐ Yes	☑ No

N. Statement of opinion

136. Does the Report include the statements of opinion required by the SOP (data, assumptions, methods, accepted actuarial practice)?	☑ Yes	☐ No
136a. Are any of the actuary's statements of opinion qualified?	☐ Yes	☑ No

Part III – Information required by the Financial Services Commission of Ontario

Financial Services Commission of Ontario | Commission des services financiers de l'Ontario

O. Additional valuation information

Going-concern valuation

140. Have escalated adjustments been included in going-concern liabilities? ☐ N/A ☑ Yes ☐ No

Solvency valuation

141. Have any of the "excludable" benefits been excluded? ☐ N/A ☑ Yes ☐ No

142. If line **141.** is "Yes", enter the total amount of liabilities being excluded: 107,030,000

P. Miscellaneous

145. Prior year credit balance: 0

146. Transfer ratio (express in decimal format): 0.90

Guarantee fund assessment

147. PBGF liabilities: 0

148. PBGF assessment base: 0

149. Amount of additional liability for plant closure and/or permanent layoff benefits as described in clause 37(4)(a)(ii)(A) of Regulation 909, R.R.O. 1990, as amended: 0

149a. Number of Ontario plan beneficiaries: 3,240

Part IV – Information required by the Office of the Superintendent of Financial Institutions Canada

Office of the Superintendent of Financial Institutions Canada | Bureau du surintendant des institutions financières du Canada

Q. Additional solvency valuation information

150. Has a smoothing method been used to determine solvency assets? ☐ Yes ☐ No

150a. Has the method used to determine assets changed since the last valuation? ☐ Yes ☐ No

If the answer to line **150a.** is "Yes", complete line **150b.** or **150c.**, as appropriate:

150b. The change in method increases solvency assets by the amount of $ _____

150c. The change in method decreases solvency assets by the amount of $ _____

160. Solvency ratio (express in decimal format): _____

161. Actuarial Present Value of Special Payments to be made within five years of the valuation date, prior to the determination of any solvency deficiency on that date (see instructions): _____

162. Liability for active members who are within ten years of pensionable age and whose entitlement is valued at an interest rate basis stated on line **045.**: _____

163. Liability for active members who are within ten years of pensionable age and whose entitlement is valued at an interest rate basis stated on line **046.**: _____

164. Liability for active members who are not within ten years of pensionable age: _____

165. Pensionable age:

a. May a member become entitled – with no employer consent required – to an unreduced retirement pension prior to the normal retirement age? ☐ Yes ☐ No

b. If "Yes" to a., state the applicable age and/or service conditions:

		Age requirement	Service requirement			Age requirement	Service requirement
Active members	1)			Deferred vested members	1)		
	2)				2)		
	3)				3)		
	4)				4)		
	5)				5)		

c. Are these benefits reflected in the solvency valuation? ☐ N/A ☐ Yes ☐ No

166. Do the liabilities determined in the Report include the impact of one or several plan amendment(s) that affect the value of benefits having accrued prior to the Report's valuation date, and which were not included in the prior report? ☐ Yes ☐ No

167. Does the Report account for one or several plan amendment(s) that affect only the cost of benefits that will accrue after the Report's valuation date, and which were not included in the prior report? ☐ Yes ☐ No

168. If the answer to either question **166.** or **167.** is "Yes", provide the amendment number and effective date: _____ Amendment number

YYYY MM DD Effective date

Part V – Information required by the Canada Revenue Agency

R. Additional information

173. Surplus/deficit determined at the valuation date as per the instructions:

173a. Going-concern basis 57,163,000

173b. Wind-up basis ..... -76,408,900

173c. For designated plans, maximum funding valuation basis .....

174. Excess surplus determined at the valuation date:

174a. Going-concern basis 0

174b. For designated plans, maximum funding valuation basis .....

175. For designated plans, employer normal cost determined under the maximum funding valuation basis:

Period 1 .....

Period 2 .....

Period 3 .....

Period 4 .....

176. Minimum surplus required under applicable pension benefit legislation before contribution holiday:

176a. Going-concern basis 1

176b. Wind-up basis 1

177. Maximum amount that could be claimed as eligible employer contribution(s) – defined benefit provisions – under subsection 147.2(2) of the *Income Tax Act:*

177a. Unfunded liability 76,408,900

177b. Normal Cost:

Period 1 14,695,100

Period 2 .....

Period 3 .....

Period 4 .....

Part VI – Information required by the Régie des rentes du Québec

Régie des rentes Québec

S. Additional information

185. Date on which the valuation report was prepared ..... YYYY MM DD

186. Value of additional obligations arising from an amendment on a funding basis .....

187. Value of additional obligations arising from an amendment on a solvency basis .....

188. Surplus assets that can be appropriated to the payment of employer contributions .....

189. Special amortization payments .....

190. Total of the letters of credit taken into account in the assets on a solvency basis .....

191. Pensions insured by an insurer taken into account in the actuarial valuation on a solvency basis .....

T. Additional information for plans whose employer is a municipality, a municipal housing bureau, an educational institution at the university level or a childcare service

195. Reserve on a funding basis .....

196. Provision for adverse deviations on a funding basis .....

	Present value	Amortization payments		
		Period 1	Period 2	Period 3
197. Technical funding deficiency				
198. Improvement funding deficiency				

U. Additional information pertaining to pension plans other than those mentioned in section T

200. Reserve on a solvency basis .....

201. Provision for adverse deviations on a solvency basis .....

	Present value	Amortization payments		
		Period 1	Period 2	Period 3
202. Funding deficiency				
203. Technical solvency deficiency				
204. Improvement solvency deficiency				

Part VII – Certification by Actuary

As the actuary who signed the funding valuation report (the "Report"), I certify that this Actuarial Information Summary accurately reflects the information provided in the Report.

Dated this 30 (day) day of September (month), 2010 (year)

Signature of actuary

Chris Heller
Print or type name of actuary

Mercer
Name of firm

403-476-3253
Telephone number

MERCER

MARSH MERCER KROLL
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403 269 4945

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03 February 2012

Enbridge Gas Distribution Inc.

Actuarial Valuation Report
Pension Expense and Employer Disclosure for the Fiscal Year Ending December 31, 2011 Under CICA Section 3461

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Report Highlights

Mercer has prepared this report to assist Enbridge Gas Distribution Inc. and its subsidiary companies (the "Company") and its auditors in preparing financial reports under Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461") relating to the following plans, known collectively as the Enbridge Gas Distribution Inc. Retirement Plans, for the fiscal year ending December 31, 2011:

- The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "RPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP").

The RPP has a defined contribution component as well as a defined benefit component. The results presented in this report consider both components of the RPP. The RPP is funded by contributions from EGD unless it elects to use a funding excess to meet annual contribution requirements. Pension benefits payable from the defined benefit component are based on length of service and final average earnings and are partially indexed for inflation after retirement.

The SERP and the SSERP are closed plans, funded by contributions from EGD as necessary. Pension benefits are based on length of service and final average earnings and are partially indexed for inflation after retirement. There are no longer any active members in the SSERP.

Enbridge Gas Distribution Inc.'s fiscal year end date is December 31, and the measurement date for the plan assets and obligations as described in this report is December 31.

Employer contributions to the pension funds during the fiscal year ending December 31, 2011 were $567,800. These employer contributions were made in

accordance with the following reports effective December 31, 2010 (the "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, effective December 31, 2010;
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates, effective December 31, 2010; and,
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc., effective December 31, 2010.

The next actuarial valuation for funding purposes in respect of the RPP must be as of a date no later than December 31, 2012.

Changes in Plan Provisions

There were no changes in plan provisions since the last disclosure as of December 31, 2010.

Changes in Actuarial Cost Methods

There were no changes in actuarial cost methods since the last disclosure as of December 31, 2010.

However, there was a change in methodology for determining interest on the DB current service cost. Interest on the DB current service cost is now included in the current service cost itself (it was previously included in the interest cost).

This change in methodology only affects the allocation of costs between components, and has no impact on the net periodic pension cost or the accrued benefit obligation at year-end.

Changes in Asset Valuation Method

There were no changes in asset valuation method since the last disclosure as of December 31, 2010.

Changes in Assumptions

There were changes in actuarial assumptions since the last disclosure as of December 31, 2010. Please see the Summary of Assumptions in Appendix A of this report for a description of these changes.

Changes in Accounting Policies

There were no changes in accounting policies since the last disclosure as of December 31, 2010.

Transition to US Accounting Standards

Enbridge will be adopting US accounting standards on January 1, 2012. Due to the requirement to provide comparative information in the first set of financial statements, Enbridge has transitioned to US accounting standards from current Canadian GAAP as of January 1, 2011. On that date, a transition adjustment was made to retained earnings to bring the existing current CICA 3461 balances in line with the requirements of US accounting standards. Enbridge will continue to report under current Canadian GAAP in 2011. Two sets of financial results were maintained for 2011, one for current Canadian GAAP and another one for US accounting standards. In 2012, current Canadian GAAP will cease to exist and US accounting standards will commence with comparative information for 2011.

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Principal Expense and Disclosure Information

A summary of principal pension expense and disclosure information, as required for disclosure purposes pursuant to CICA 3461, from the current fiscal year and the prior fiscal year follows.

Components of Net Periodic Pension Cost	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Current service cost - DB	$16,710,900	$13,675,700
Current service cost - DC	1,345,400	1,717,500
Interest cost	38,937,100	38,390,500
Actual return on DB plan assets	(15,158,900)	(78,793,700)
Actuarial loss (gain) on accrued benefit obligation	125,704,600	80,807,600
Costs arising in the period	**$167,539,100**	**$55,797,600**
Differences between costs arising in the period and costs recognized in the period in respect of:		
▪ Return on plan assets	(37,767,700)	29,215,700
▪ Actuarial loss (gain)	(110,298,200)	(67,993,400)
▪ Past service cost	1,270,600	1,270,600
▪ Transitional obligation (asset)	(25,721,000)	(25,721,000)
Net periodic pension cost recognized	**($4,977,200)**	**($7,430,500)**

Weighted-Average Assumptions for Expense	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Discount rate	5.70%	6.60%
Expected long-term rate of return on plan assets	7.19%	7.18%
Rate of compensation increase	3.50%	3.50%

Weighted-Average Assumptions for Disclosure	December 31, 2011	December 31, 2010
Discount rate	4.50%	5.70%
Rate of compensation increase	3.50%	3.50%

Change in Accrued Benefit Obligation	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Accrued benefit obligation at end of prior year	**$699,580,700**	**$598,176,600[1]**
Current service cost - DB	16,710,900	13,675,700
Interest cost	38,937,100	38,390,500
Employee contributions	0	0
Benefits paid	(32,949,500)	(31,469,700)
Actuarial loss (gain)	125,704,600	80,807,600[2]
Accrued benefit obligation at end of year	**$847,983,800**	**$699,580,700**

Change in Plan Assets	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Fair value of plan assets at end of prior year	**$758,390,900**	**$711,836,200[3]**
Actual return on plan assets	15,158,900	78,793,700[4]
Employer contributions	567,800	948,200
Employee contributions	0	0
Benefits paid	(32,949,500)	(31,469,700)
DC contributions drawn from DB surplus	(1,345,400)	(1,717,500) [5]
Fair value of plan assets at end of year	**$739,822,700**	**$758,390,900**

[1] Based on September 30 measurement date.

[2] Includes a gain from change in measurement date of $22,204,300.

[3] Based on September 30 measurement date.

[4] Includes a gain from change in measurement date of $15,757,100

[5] Includes DC contributions from DB surplus between October 1, 2010 to December 31, 2010 of $319,300.

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Excess (deficit) at end of year	**($108,161,100)**	**$58,810,200**
Unamortized transitional obligation (asset)	(44,783,400)	(70,504,400)
Unamortized past service costs	2,470,600	3,741,200
Unamortized net actuarial loss (gain)	376,467,500	228,401,600
Accrued benefit asset (liability)	**$225,993,600**	**$220,448,600**

Weighted-Average Invested Plan Assets by Category	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Equity securities	49%	52%
Debt securities	45%	41%
Other	6%	7%
Total	**100%**	**100%**

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Certification

Mercer has prepared this report exclusively to assist Enbridge Gas Distribution Inc. and its subsidiary companies and auditors in preparing financial reports under Section 3461 of the Canadian Institute of Chartered Accountants Handbook relating to the Enbridge Gas Distribution Inc. Retirement Plans for the fiscal year ending December 31, 2011.

This valuation report may not be used or relied upon by any other party or for any other purpose. Mercer is not responsible for the consequences of any unauthorized use.

A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, plan expenses and the amount earned on any assets invested to pay the benefits. These amounts and others are uncertain and unknowable at the valuation date, but are predicted to fall within a reasonable range of possibilities.

To prepare this report, *actuarial assumptions*, as described in Appendix A, are used to select a single scenario from the range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in mandated requirements, plan experience, changes in expectations about the future, and other factors. Due to the limited scope of the assignment, we did not perform, and thus do not present, an analysis of the potential range of future possibilities and scenarios.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related

issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

Actuarial Valuations and Extrapolations

We have prepared an actuarial valuation of the Enbridge Gas Distribution Inc. Retirement Plans' accrued benefit obligations for accounting purposes as at December 31, 2009 and extrapolated those results to December 31, 2010. The extrapolation of the accrued benefit obligations is based on assumptions as at December 31, 2010 and on actual cash flows for fiscal 2010. In accordance with our mandate, the purpose of this valuation and extrapolation is to account for the costs of the plan for the fiscal year beginning January 1, 2011 and ending December 31, 2011 in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461").

In addition, we have prepared a second actuarial valuation of the Enbridge Gas Distribution Inc. Retirement Plans' accrued benefit obligations for accounting purposes as at December 31, 2010 and extrapolated those results to December 31, 2011. The extrapolation of the accrued benefit obligations is based on assumptions as at December 31, 2011 and on actual cash flows for fiscal 2011. In accordance with our mandate, the purpose of this valuation and extrapolation is to enable Enbridge to satisfy year-end disclosure requirements under CICA 3461.

The financial positions of the plan and the determination of net periodic pension cost set out in this report are based on unaudited financial statements as of December 31, 2010 and December 31, 2011.

Plan Provisions

The results of the valuations set forth in this report reflect the contractual provisions of the plans as of the dates of the valuations and extrapolations as reported to us by Management.

The plans have not been amended since the last valuation and extrapolation for accounting purposes as at December 31, 2010. A summary of the plan provisions is provided in Appendix F of the following reports (the "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, effective December 31, 2010;
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates, effective December 31, 2010; and,
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc., effective December 31, 2010.

Substantive Commitment

There was no substantive commitment as defined under CICA 3461 reported to us by Management.

Data

The valuations are based on the plan asset data presented in the unaudited trust statements prepared by CIBC Mellon for the period from January 1, 2010/ January 1, 2011 to December 31, 2010/December 31, 2011. The pension fund is held in trust by CIBC Mellon and is invested in accordance with the investment policy of Enbridge Gas Distribution Inc. Plan assets of the SERP and SSERP also include the refundable tax account held by the Canada Revenue Agency (the "CRA").

The plan asset data are summarized in the Principal Expense and Disclosure Information section of this report. We have tested the pensions paid and the lump-sum refunds for consistency with the membership data for the plan members who have received benefits. The results of these tests were satisfactory.

The valuations are also based on the membership data as at December 31, 2010 provided by Enbridge Gas Distribution Inc. The membership data, and the validation checks made on the data, are summarized in Appendix E of the Funding Reports.

Subsequent Events

After checking with representatives of Enbridge Gas Distribution Inc., to our knowledge there have been no events subsequent to December 31, 2011 which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

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

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions used in the valuations and determination of net periodic pension cost are summarized in this report.

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Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of Section 3461 of the CICA Handbook.

The preparers of the financial statements have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with Section 3461 of the CICA Handbook. We are not expressing any opinion on these assumptions.

In our opinion,

- The data on which the valuations are based are sufficient and reliable for the purposes of the valuations; and
- The calculations have been made in accordance with the requirements of Section 3461 of the CICA Handbook, reflecting application of Enbridge Gas Distribution Inc.'s accounting policies described in this report.

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

Respectfully submitted,

Allen Hornung	Sarah Fitzmaurice
FSA, FCIA	FSA, FCIA
03 February 2012	03 February 2012
Date	Date

Appendix A

Valuation Methods and Assumptions

This Appendix describes the methods and assumptions used to value the plan as well as the accounting policies used to calculate the net periodic pension cost.

Actuarial Cost Method

Accrued benefit obligations shown in this report are computed using the Projected Benefit Method Pro Rated on Services as defined in CICA 3461. The objective under this method is to expense each participant's benefits under the plan as they would accrue, taking into consideration future salary increases and the plan's benefit allocation formula. The accrued benefit is determined under this method as follows:

Under the Projected Benefit Method Pro Rated on Services an equal portion of the total estimated future benefit (i.e., with salary projection or cost escalation, where appropriate), is attributed to each year of service.

The accrued benefit obligation is the actuarial present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

The plan's **current service cost** is the sum of the individual current service costs, and the plan's **accrued benefit obligation** is the sum of the individual accrued benefit obligations for all participants under the plan.

Method for Determining Market-Related Value of Plan Assets

The market value of plan assets has been used to determine the net periodic pension cost for the fiscal year ended December 31, 2011 and for disclosure purposes as at December 31, 2011.

Accounting Policies

Management applied the Recommendations of Section 3461 of the CICA Handbook prospectively and elected to amortize the transitional (asset)/obligation on a linear basis over the average remaining service of active members expected to receive benefits under the plan.

Future salary levels and inflation affect the amount of future pensions. The projected benefit method prorated on services has been used to determine the accrued benefit obligation and current service cost.

The expected return on plan assets is based on the fair value of plan assets.

Enbridge has elected to amortize past service costs resulting from plan amendments on a linear basis over the average remaining service period of active members expected to receive benefits under the plan.

Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation and the market-related value of plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan.

Enbridge Gas Distribution Inc.'s fiscal year-end date is December 31 and the measurement date of the plan's assets and obligations is December 31. The measurement date was changed from September 30 to December 31 in fiscal 2010. The impact of this change is included as an actuarial gain/loss in the period.

Obligations are attributed to the period beginning on the employee's date of joining the plan and ending on earlier of the date of termination, death or retirement.

Summary of Assumptions

The following assumptions were used in valuing the accrued benefit obligations under the plan and the employer's net periodic pension cost.

Measurement date	▪ September 30 for the 2010 expense determination ▪ December 31 for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Discount rate	▪ 6.60% per year for the 2010 expense determination ▪ 5.70% per year for the December 31, 2010 funded status and 2011 expense determination ▪ 4.50% per year for the December 31, 2011 funded status[6]
Long-term rate of return on invested assets	▪ 7.25% per year for the 2010 and 2011 expense determination
Increases in pensionable earnings	▪ 3.50% per year
Increases in the YMPE	▪ 2.50% per year for the 2010 expense determination ▪ 2.75% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Increases in maximum pension permitted under the *Income Tax Act*	▪ 2.50% per year for the 2010 expense determination ▪ 2.75% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Consumer Price Index	▪ 2.00% per year for the 2010 expense determination ▪ 2.25% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Indexation of pensions in payment	▪ 1.10% per year in respect of Contributory service, 1.00% per year in respect of Non-Contributory and Senior Manager service for the 2010 expense determination ▪ 1.24% per year in respect of Contributory service, 1.13% per year in respect of Non-Contributory and Senior Manager service for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Mortality	UP-1994 generational mortality table using scale AA
Disability	No allowance for future disabilities
Withdrawal	See tables of sample rates
Expenses	Implicit in long-term rate of return on assets
Retirement	See table of sample rates

[6] The discount rate as of December 31, 2011 was determined in accordance with the methodology proposed by the Canadian Institute of Actuaries in September 2011.

Percentage with spouse	80% married
Age difference	A male is assumed to be 2 years older than his spouse
Headcount	No allowance made for headcount growth

Sample rates from the age related tables are summarized below:

Age	Termination - Male	Termination - Female	Retirement
20	5.0%	9.5%	0.0%
25	5.0%	13.0%	0.0%
30	5.0%	11.0%	0.0%
35	4.6%	8.5%	0.0%
40	3.0%	4.0%	0.0%
45	2.5%	3.9%	0.0%
50	1.5%	2.8%	0.0%
55	0.0%	0.0%	5.0%
56	0.0%	0.0%	5.0%
57	0.0%	0.0%	7.5%
58	0.0%	0.0%	7.5%
59	0.0%	0.0%	10.0%
60	0.0%	0.0%	20.0%
61	0.0%	0.0%	20.0%
62	0.0%	0.0%	20.0%
63	0.0%	0.0%	20.0%
64	0.0%	0.0%	20.0%
65	0.0%	0.0%	100.0%

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

Appendix B

Results by Participating Employers

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

Decmeber 31, 2011 Measurement
Enbridge Gas Distribution Pension Plans - RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	663,169,500	10,461,100	7,007,900	680,638,500
Current service cost (employer)	15,754,900	376,600	579,400	16,710,900
Interest cost	36,917,700	588,200	391,800	37,897,700
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(30,845,700)	(352,900)	(348,200)	(31,546,800)
Net transfer in (out)	196,200	(160,800)	(35,400)	-
Actuarial loss (gain)	119,244,500	2,411,100	1,718,600	123,374,200
Benefit obligation - end	804,437,100	13,323,300	9,314,100	827,074,500
Change in plan assets				
Market value of plan assets - end of prior period	718,163,500	10,690,500	6,129,900	734,983,900
Actual return on plan assets	14,090,400	216,000	125,300	14,431,700
Employer contributions	-	-	-	-
Employee contributions	-	-	-	-
Benefits paid	(30,845,700)	(352,900)	(348,200)	(31,546,800)
DC contributions paid from DB surplus	(1,211,100)	(60,700)	(73,600)	(1,345,400)
Net transfer in (out)	170,500	(138,700)	(31,800)	-
Market value of plan assets - end	700,367,600	10,354,200	5,801,600	716,523,400
Reconciliation of funded status				
Funded status - surplus (deficit)	(104,069,500)	(2,969,100)	(3,512,500)	(110,551,100)
Unamortized transitional obligation (asset)	(41,889,000)	(399,400)	(204,000)	(42,492,400)
Unamortized past service costs	2,397,900	22,900	11,700	2,432,500
Unamortized net actuarial loss (gain)	361,078,000	5,338,200	2,991,000	369,407,200
Accrued benefit asset (liability)	217,517,400	1,992,600	(713,800)	218,796,200
Components of expense				
Current service cost (including provision for plan expenses)	15,754,900	376,600	579,400	16,710,900
Interest cost	36,917,700	588,200	391,800	37,897,700
Expected return on plan assets	(50,896,800)	(762,600)	(431,600)	(52,091,000)
Amortization of transitional obligation (asset)	(24,556,700)	(234,200)	(119,600)	(24,910,500)
Amortization of past service costs	1,202,200	11,500	5,900	1,219,600
Amortization of net actuarial loss (gain)	14,546,200	216,500	124,200	14,886,900
Net expense (income)	(7,032,500)	196,000	550,100	(6,286,400)
Current Service Cost - DC	1,211,100	60,700	73,600	1,345,400

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SERP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	13,033,200	-	-	13,033,200
Current service cost (employer)	-	-	-	-
Interest cost	718,400	-	-	718,400
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(909,600)	-	-	(909,600)
Net transfer in (out)	-	-	-	-
Actuarial loss (gain)	2,226,700	-	-	2,226,700
Benefit obligation - end	15,068,700	-	-	15,068,700
Change in plan assets				
Market value of plan assets - end of prior period	15,431,600	-	-	15,431,600
Actual return on plan assets	445,700	-	-	445,700
Employer contributions	567,800	-	-	567,800
Employee contributions	-	-	-	-
Benefits paid	(909,600)	-	-	(909,600)
Net transfer in (out)	-	-	-	-
Market value of plan assets - end	15,535,500	-	-	15,535,500
Reconciliation of funded status				
Funded status - surplus (deficit)	466,800	-	-	466,800
Employer contributions after measurement date	-	-	-	-
Unamortized transitional obligation (asset)	(390,200)	-	-	(390,200)
Unamortized past service costs	38,200	-	-	38,200
Unamortized net actuarial loss (gain)	5,366,800	-	-	5,366,800
Accrued benefit asset (liability)	5,481,600	-	-	5,481,600
Components of expense				
Current service cost (including provision for plan expenses)	-	-	-	-
Interest cost	718,400	-	-	718,400
Expected return on plan assets	(556,100)	-	-	(556,100)
Amortization of transitional obligation (asset)	(565,200)	-	-	(565,200)
Amortization of past service costs	51,000	-	-	51,000
Amortization of net actuarial loss (gain)	461,700	-	-	461,700
Net expense (income)	109,800	-	-	109,800
		-	-	
Composition of ending asset balance 12/31/2011				
Market value of RCA invested assets as per CIBC Mellon statement	7,951,500	-	-	7,951,500
Estimated value of Refundable Tax Account (RTA)	7,584,000	-	-	7,584,000
Market value of assets for disclosure	15,535,500	-	-	15,535,500

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SSERP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	5,909,000	-	-	5,909,000
Current service cost (employer)	-	-	-	-
Interest cost	321,000	-	-	321,000
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(493,100)	-	-	(493,100)
Net transfer in (out)	-	-	-	-
Actuarial loss (gain)	103,700	-	-	103,700
Benefit obligation - end	5,840,600	-	-	5,840,600
Change in plan assets				
Market value of plan assets - end of prior period	7,975,300	-	-	7,975,300
Actual return on plan assets	281,500	-	-	281,500
Employer contributions	-	-	-	-
Employee contributions	-	-	-	-
Benefits paid	(493,100)	-	-	(493,100)
Net transfer in (out)	-	-	-	-
Market value of plan assets - end	7,763,700	-	-	7,763,700
Reconciliation of funded status				
Funded status - surplus (deficit)	1,923,100	-	-	1,923,100
Employer contributions after measurement date	-	-	-	-
Unamortized transitional obligation (asset)	(1,900,800)	-	-	(1,900,800)
Unamortized past service costs	-	-	-	-
Unamortized net actuarial loss (gain)	1,693,500	-	-	1,693,500
Accrued benefit asset (liability)	1,715,800	-	-	1,715,800
Components of expense				
Current service cost (including provision for plan expenses)	-	-	-	-
Interest cost	321,000	-	-	321,000
Expected return on plan assets	(279,500)	-	-	(279,500)
Amortization of transitional obligation (asset)	(245,300)	-	-	(245,300)
Amortization of past service costs	-	-	-	-
Amortization of net actuarial loss (gain)	57,800	-	-	57,800
Net expense (income)	(146,000)	-	-	(146,000)
Composition of ending asset balance 12/31/2011				
Market value of RCA invested assets as per CIBC Mellon statement	2,715,400	-	-	2,715,400
Estimated value of EBP invested assets as per CIBC Mellon statement	2,541,900	-	-	2,541,900
Estimated value of Refundable Tax Account (RTA)	2,506,400	-	-	2,506,400
Market value of assets for disclosure	7,763,700	-	-	7,763,700

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Appendix C

Additional Disclosures

Enbridge Gas Distribution

	2011				
	EGD RPP	EGD DC	EGD SERP	EGD SSERP	Total
Additional year-end information					
1. Sensitivity to key assumptions					
a. Half a percent decrease in expected return on assets					
i. Effect on pension expense	3,592,000	n/a	38,000	19,000	3,649,000
ii. Effect on year-end accrued benefit obligation	n/a	n/a	n/a	n/a	n/a
b. Half a percent decrease in discount rate					
i. Effect on pension expense	6,276,000	n/a	126,000	2,000	6,404,000
ii. Effect on year-end accrued benefit obligation	59,730,000	n/a	733,000	239,000	60,702,000
b. Half a percent decrease in rate of salary increase					
i. Effect on pension expense	(1,612,000)	n/a	(15,000)	-	(1,627,000)
ii. Effect on year-end accrued benefit obligation	(7,578,000)	n/a	(59,000)	-	(7,637,000)
2. Expected DB benefit payments					
31-Dec-2011 :					
31-Dec-2012 :	32,686,000	n/a	944,000	531,000	34,161,000
31-Dec-2013 :	33,993,000	n/a	982,000	552,000	35,527,000
31-Dec-2014 :	35,353,000	n/a	1,021,000	574,000	36,948,000
31-Dec-2015 :	36,767,000	n/a	1,062,000	597,000	38,426,000
31-Dec-2016 :	38,238,000	n/a	1,104,000	621,000	39,963,000
Next five years	215,397,000	n/a	6,220,000	3,500,000	225,117,000
3. Expected contributions in following year	16,952,000	1,497,000	677,000	-	19,126,000

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - RPP

Expected benefit payments				
31-Dec-2012 :	32,001,000			
31-Dec-2013 :	33,281,000			
31-Dec-2014 :	34,612,000			
31-Dec-2015 :	35,996,000			
31-Dec-2016 :	37,436,000			
Next five years	210,873,000			
Expected contributions				
31-Dec-2012 :	15,959,000	407,000	586,000	16,952,000
31-Dec-2013 :	33,169,000	685,000	783,000	34,637,000
31-Dec-2014 :	29,583,000	635,000	762,000	30,980,000
31-Dec-2015 :	26,697,000	596,000	750,000	28,043,000
31-Dec-2016 :	24,395,000	567,000	746,000	25,708,000
31-Dec-2017 :	22,586,000	545,000	746,000	23,878,000
31-Dec-2018 :	21,188,000	531,000	752,000	22,471,000
31-Dec-2019 :	17,271,000	441,000	634,000	18,344,000
31-Dec-2020 :	14,187,000	362,000	521,000	15,069,000
31-Dec-2021 :	14,689,000	375,000	540,000	15,603,000

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SERP

Expected benefit payments				
31-Dec-2012 :	944,000			
31-Dec-2013 :	982,000			
31-Dec-2014 :	1,021,000			
31-Dec-2015 :	1,062,000			
31-Dec-2016 :	1,104,000			
Next five years	6,220,000			
Expected contributions				
31-Dec-2012 :	677,000	-	-	677,000
31-Dec-2013 :	695,000	-	-	695,000
31-Dec-2014 :	176,000	-	-	176,000
31-Dec-2015 :	121,000	-	-	121,000
31-Dec-2016 :	77,000	-	-	77,000
31-Dec-2017 :	42,000	-	-	42,000
31-Dec-2018 :	14,000	-	-	14,000
31-Dec-2019 :	-	-	-	-
31-Dec-2020 :	-	-	-	-
31-Dec-2021 :	-	-	-	-

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SSERP

Expected benefit payments				
31-Dec-2012 :	531,000			
31-Dec-2013 :	552,000			
31-Dec-2014 :	574,000			
31-Dec-2015 :	597,000			
31-Dec-2016 :	621,000			
Next five years	3,500,000			
Expected contributions				
31-Dec-2012 :	-	-	-	-
31-Dec-2013 :	-	-	-	-
31-Dec-2014 :	-	-	-	-
31-Dec-2015 :	-	-	-	-
31-Dec-2016 :	-	-	-	-
31-Dec-2017 :	-	-	-	-
31-Dec-2018 :	-	-	-	-
31-Dec-2019 :	-	-	-	-
31-Dec-2020 :	-	-	-	-
31-Dec-2021 :	-	-	-	-

Filed: 2012-08-03
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Appendix D

Employer Certification

With respect to the Actuarial Valuation Report on Pension Expense and Employer Disclosure for the Fiscal Year Ending December 31, 2011 Under CICA Section 3461 of the Enbridge Gas Distribution Inc. Retirement Plans, I hereby certify that, to the best of my knowledge and belief:

- the membership data supplied to the actuary provide a complete and accurate description of all persons who are entitled to benefits under the terms of the plan for service up to the date of the valuation;
- a copy of the official plan documents and of all amendments made up to December 31, 2011 were supplied to the actuary;
- all substantive commitments (as defined under CICA 3461) have been communicated to the actuary;
- accounting policies as adopted by the company are those described in this report.
- the actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- the management best estimate assumptions for purposes of the valuations and the extrapolation of the financial position of the plan as of the fiscal year end December 31, 2011 are those described in this report; and
- all events subsequent to the valuation that may have an impact on the results of the valuation or of a future valuation have been communicated to the actuary.

February 13, 2012.
Date

J L Whelan.
Signed
John K. Whelan.
Name
Sr. Vice President & Controller
Title

Sonia Héroux
Signed
SONIA HEROUX
Name
SR. MANAGER PENSION AND BENEFITS.
Title

MERCER

Mercer (Canada) Limited
222 – 3rd Avenue South West
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ENBRIDGE GAS DISTRIBUTION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2011

MANAGEMENT'S REPORT

To the Shareholders of Enbridge Gas Distribution Inc.

Financial Reporting
Management of Enbridge Gas Distribution Inc. (the Company) is responsible for the accompanying consolidated financial statements and all other information in this Annual Report. The consolidated financial statements have been prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants Handbook and necessarily include amounts that reflect management's judgment and best estimates. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit, Finance & Risk Committee (AF&RC) of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfil its responsibilities for financial reporting and internal controls related thereto. The AF&RC meets with management, internal auditors and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The AF&RC reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting
Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting includes policies and procedures to facilitate the preparation of relevant, reliable and timely information, to prepare consolidated financial statements for external reporting purposes in accordance with generally accepted accounting principles and provide reasonable assurance that assets are safeguarded.

PricewaterhouseCoopers LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the consolidated financial statements in accordance with Canadian generally accepted auditing standards.

(Signed)

D. Guy Jarvis
President, Gas Distribution

(Signed)

Narinder K. Kishinchandani
Vice President, Finance

February 14, 2012

February 14, 2012

Independent Auditor's Report

To the Shareholders of Enbridge Gas Distribution Inc.

We have audited the accompanying consolidated financial statements of Enbridge Gas Distribution Inc. and its subsidiaries, which comprise the consolidated statements of financial position as at December 31, 2011 and 2010 and the consolidated statements of earnings, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Gas Distribution Inc. and its subsidiaries as at December 31, 2011 and 2010 and the results of its operations and cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(Signed) "PricewaterhouseCoopers LLP"

Chartered Accountants, Licensed Public Accountants

PricewaterhouseCoopers LLP Chartered Accountants
PwC Tower, 18 York Street, Suite 2600, Toronto, Ontario, Canada M5J 0B2
T: +1 416 863 1133, F: +1 416 365 8215, www.pwc.com/ca

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Gas commodity and distribution revenue *(Note 20)*	**2,010**	1,977
Transportation of gas for customers	**352**	390
	2,362	2,367
Gas commodity and distribution costs excluding depreciation *(Note 20)*	**(1,341)**	(1,372)
Gas distribution margin	**1,021**	995
Other revenue	**104**	108
	1,125	1,103
Expenses		
Operating and administrative *(Note 20)*	**419**	393
Depreciation and amortization	**281**	270
Municipal and other taxes	**41**	44
Earnings sharing *(Note 3)*	**13**	19
	754	726
	371	377
Affiliate financing income *(Note 20)*	**63**	63
Interest expense *(Notes 10 and 20)*	**(172)**	(186)
	262	254
Income taxes *(Note 17)*		
Current	**(50)**	(59)
Future	**(1)**	(2)
	(51)	(61)
Earnings	**211**	193
Preferred share dividends	**(2)**	(2)
Earnings attributable to the common shareholder	**209**	191

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Earnings	**211**	193
Other comprehensive income/(loss)		
Change in unrealized loss on cash flow hedges, net of tax	**(1)**	(17)
Reclassification to earnings of realized gains on cash flow hedges, net of tax	**2**	2
Change in foreign currency translation adjustment	**-**	(1)
Other comprehensive income/(loss)	**1**	(16)
Comprehensive income	**212**	177

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Preferred shares *(Note 12)*	**100**	100
Common shares *(Note 12)*		
Balance at beginning of year	**1,071**	1,071
Common shares issued	**66**	-
Balance at end of year	**1,137**	1,071
Contributed surplus	**202**	202
Retained earnings		
Balance at beginning of year	**572**	596
Earnings attributable to the common shareholder	**209**	191
Common share dividends declared	**(220)**	(215)
Balance at end of year	**561**	572
Accumulated other comprehensive loss		
Balance at beginning of year	**(18)**	(2)
Other comprehensive income	**1**	(16)
Balance at end of year	**(17)**	(18)
Total shareholders' equity	**1,983**	1,927

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating activities		
Earnings	**211**	193
Depreciation and amortization	**281**	270
Future income taxes	**1**	2
Other	**4**	2
Changes in operating assets and liabilities *(Note 19)*	**17**	45
	514	512
Investing activities		
Additions to property, plant and equipment	**(441)**	(345)
Additions to intangible assets	**(34)**	(20)
Change in construction payable	**5**	-
Other	**6**	-
	(464)	(365)
Financing activities		
Change in bank overdraft	**(10)**	(11)
Net change in short-term borrowings	**222**	(182)
Issue of short-term note payable to affiliate company *(Note 20)*	**5**	2
Repayment of short-term note payable to affiliate company *(Note 20)*	**(3)**	(3)
Debenture and term note issues	**100**	402
Debenture and term note repayments	**(150)**	(150)
Preferred share dividends	**(2)**	(2)
Common share dividends	**(218)**	(208)
Other	**2**	(2)
	(54)	(154)
Decrease in cash and cash equivalents	**(4)**	(7)
Cash and cash equivalents at beginning of year	**13**	20
Cash and cash equivalents at end of year	**9**	13
Supplementary cash flow information		
Income taxes paid	**62**	59
Interest paid *(Note 10)*	**169**	185

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2011**	2010
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**9**	13
Accounts receivable and other *(Notes 5 and 20)*	**663**	802
Gas inventories	**380**	400
	1,052	1,215
Property, plant and equipment, net *(Note 6)*	**4,770**	4,458
Investment in affiliate company *(Note 20)*	**825**	825
Deferred amounts and other assets *(Note 7)*	**489**	487
Intangible assets *(Note 8)*	**179**	167
	7,315	7,152
Liabilities and shareholders' equity		
Current liabilities		
Bank overdraft	**7**	17
Short-term borrowings *(Note 10)*	**556**	332
Accounts payable and other *(Notes 9 and 20)*	**713**	850
Current maturities of long-term debt *(Note 10)*	**-**	150
Future income taxes *(Note 17)*	**2**	5
	1,278	1,354
Long-term debt *(Note 10)*	**2,374**	2,267
Other long-term liabilities *(Note 11)*	**1,127**	1,058
Future income taxes *(Note 17)*	**178**	171
Loans from affiliate company *(Notes 10 and 20)*	**375**	375
	5,332	5,225
Shareholders' equity		
Share capital		
Preferred shares *(Note 12)*	**100**	100
Common shares *(Note 12)*	**1,137**	1,071
Contributed surplus	**202**	202
Retained earnings	**561**	572
Accumulated other comprehensive loss	**(17)**	(18)
	1,983	1,927
Commitments and contingencies *(Notes 20 and 21)*		
	7,315	7,152

The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Board of Directors:

(Signed)

D. Guy Jarvis
President

(Signed)

David A. Leslie
Director

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Enbridge Gas Distribution Inc. (the Company) is a rate-regulated natural gas distribution utility, serving residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. The Company also serves areas in northern New York State through its wholly owned subsidiary, St. Lawrence Gas Company, Inc. (St. Lawrence). The Company is a wholly owned subsidiary of Enbridge Inc. (Enbridge).

The Company also owns and operates unregulated facilities in Ontario, including two solar projects located in Amherstburg, Ontario, through its 99.9% limited partnership interest in Project AMBG2 LP (Project Amherstburg) and unregulated natural gas storage facilities.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Part V – Pre-changeover Accounting Standards of The Canadian Institute of Chartered Accountants (CICA) Handbook (Canadian GAAP or Part V). Amounts are stated in Canadian dollars unless otherwise noted.

The preparation of the consolidated financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: estimates of revenue; carrying values of regulatory assets and liabilities *(Note 3)*; unbilled revenues *(Note 5)*; allowance for doubtful accounts *(Note 5)*; depreciation rates and carrying values of property, plant and equipment *(Note 6)*; amortization rates and carrying values of intangible assets *(Note 8)*; fair values of financial instruments *(Notes 14 and 15)*; income taxes *(Note 17)*; post-employment benefits *(Note 18);* contingencies *(Note 21);* and fair value of asset retirement obligations. Actual results could differ from those estimates.

BASIS OF PRESENTATION
The consolidated financial statements include the accounts of the Company and its subsidiaries. Investments are accounted for according to their classification (see Financial Instruments). All significant intercompany accounts and transactions are eliminated upon consolidation.

REGULATION
The utility operations of the Company, excluding St. Lawrence, are regulated by the Ontario Energy Board (OEB) and the utility operations of St. Lawrence are regulated by the New York State Public Service Commission (NYSPSC) (collectively the Regulators).

The Regulators exercise statutory authority over matters such as construction, rates and rate-making and agreements with customers. To recognize the economic effects of the actions of the Regulators, the timing of recognition of certain revenues and expenses in the utility operations may differ from that otherwise expected under Canadian GAAP for non rate-regulated entities.

REVENUE RECOGNITION
The Company recognizes revenues when natural gas has been delivered or services have been performed. Gas commodity and distribution revenue is recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in the Company's distribution franchise area.

A significant portion of the Company's operations are subject to regulation and accordingly, there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the Regulators. This may give rise to regulatory deferral accounts pending disposition by decisions of the Regulators.

FINANCIAL INSTRUMENTS

The Company classifies financial assets and financial liabilities as held for trading, available for sale, loans and receivables, other financial liabilities or derivatives in qualifying hedging relationships. The Company has not classified any financial assets or liabilities as held to maturity.

Held for Trading

Financial assets and liabilities that are classified as held for trading are measured at fair value with changes in fair value recognized in earnings. The Company has classified Cash and cash equivalents and Bank overdraft as held for trading.

Available for Sale

The Company classifies its investment in the preferred shares of IPL System Inc. as an available for sale financial asset. Available for sale instruments are periodically created by the Company and its affiliated companies to meet the current and future financing requirements of either the Company or its affiliated companies. This investment originated in a related party transaction. No external market for the instrument exists and no quoted market price is available in an active market. Therefore, the invesment is carried at cost and a fair value has not been determined. Dividends received from this investment are recognized in earnings when the right to receive payment is established *(Note 20)*.

Loans and Receivables

Loans and receivables, which include Accounts receivable and other, are initially recognized at fair value and subsequently measured at amortized cost using the effective interest rate method, net of any impairment losses recognized.

Other Financial Liabilities

Other financial liabilities are measured at amortized cost using the effective interest rate method and include Short-term borrowings, Accounts payable and other, Long-term debt and Loans from affiliate company.

Derivatives in Qualifying Hedging Relationships

The Company uses derivative financial instruments to manage changes in natural gas prices and interest rates. Hedge accounting is optional and requires the Company to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. The Company presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges and net investment hedges. The Company did not have any fair value hedges or net investment hedges outstanding as at December 31, 2011 and 2010.

Cash Flow Hedges

The Company uses cash flow hedges to manage changes in interest rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income (OCI) and is reclassified to earnings when the hedged item impacts earnings or to the carrying value of the related non-financial asset. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss deferred in OCI up to that date will be recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

The majority of St. Lawrence's derivatives relate to the management of natural gas prices. Given that St. Lawrence is subject to rate regulation, the effective portion of changes in the fair value of these derivatives is deferred as an asset or liability until they are settled and an offsetting asset or liability is recorded on behalf of customers. Upon settlement, the recognized gain or loss is recorded as a regulatory asset or liability and is collected from or refunded to customers in subsequent period rates.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments are offset in the Consolidated Statements of Financial Position when the Company has the legal right and intention to settle them on a net basis.

Transaction Costs
Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Company incurs transaction costs primarily through the issuance of debt and classifies these costs with the related debt. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES
The liability method of accounting for income taxes is followed. Future income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Future income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. Any interest and/or penalty incurred related to tax is reflected in income taxes

The regulated utility operations of the Company recover income tax expense based on the taxes payable method as prescribed by the Regulators for rate-making purposes. As a result, rates do not include the recovery of future income taxes related to temporary differences. A corresponding future income tax regulatory liability/asset is recorded reflecting the Company's ability to pay/collect the amounts in the future through rates.

FOREIGN CURRENCY TRANSLATION
The functional currency of the Company's only foreign operation, St. Lawrence, is the United States dollar. This operation is self-sustaining and is translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates and revenues and expenses are translated using monthly average rates. Gains and losses arising on translation of this operation are included in the foreign currency translation adjustment component of Accumulated other comprehensive loss (AOCL).

GAS INVENTORIES
Gas inventories are primarily comprised of natural gas in storage and also include costs such as storage injection and demand costs. Natural gas in storage is recorded at the prices approved by the Regulators in the determination of distribution rates. The actual price of natural gas purchased may differ from the Regulators' approved price. The difference between the approved price and the actual cost of the natural gas purchased is deferred as a liability for future refund or as an asset for collection by the Company to/from customers, as approved by the Regulators. Actual cost of natural gas for St. Lawrence includes the effect of natural gas price risk management activities.

Included in, or deducted from, gas inventories is an amount for natural gas to be received from, or returned to, direct purchase customers or agents (non-system supply customers). This amount represents the difference between natural gas received on behalf of non-system supply customers and natural gas delivered to such customers.

At December 31, 2011, $100 million of natural gas was held on behalf of transportation service customers (December 31, 2010 - $102 million). These transactions have no impact on the Company's consolidated earnings or financial position.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment are recorded at historical cost, including associated operating costs and an allowance for interest during construction at rates approved by the Regulators.

The Regulators prescribe the pool method of accounting for property, plant and equipment where similar assets with comparable useful lives are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings, but are booked as an adjustment to accumulated depreciation. Depreciation of property, plant and equipment is provided on a straight-line basis over the estimated useful lives of the assets, as approved by the Regulators, commencing when the asset is placed in service. Depreciation expense includes a provision for future removal and site restoration costs at rates approved by the Regulators.

DEFERRED AMOUNTS AND OTHER ASSETS

Deferred amounts and other assets include costs the Regulators have permitted, or are expected to permit, to be recovered through future rates, derivative financial instruments and pension assets. Certain deferred amounts are amortized on a straight-line basis over various periods depending on the nature of the charges.

INTANGIBLE ASSETS

Intangible assets consist primarily of the Customer Information System (CIS), software costs and the Project Amherstburg contracts, which are amortized on a straight-line basis over their expected useful lives, commencing when the asset is available for use.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) associated with the retirement of long-lived assets would be measured at fair value and recognized as Other Long-Term Liabilities in the period in which they could be reasonably determined. The fair value would approximate the cost a third party would charge to perform the tasks necessary to retire such assets and would be recognized at the present value of expected future cash flows. AROs would be added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability would be accreted over time through charges to earnings and would be reduced by actual costs of decommissioning and reclamation. The Company's estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements.

It is not possible to make a reasonable estimate of AROs for the Company due to the indeterminate timing of the asset retirements

POST-EMPLOYMENT BENEFITS

The Company maintains non-contributory pension plans that provide defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company also provides post-employment benefits other than pensions (OPEB), including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependants.

The Company's post-employment costs are determined as follows:

- The cost of pensions and OPEB earned by employees are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees and expected health-care and insurance costs. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.
- Pension plan assets are measured at fair value.
- The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.
- The excess of the cumulative unrecognized net actuarial gain or loss over 10% of the greater of the accrued benefit obligation and the fair value of plan assets is amortized over the expected average remaining service lives of the active employee group covered by the plans.
- The transitional asset and obligation is amortized over the expected average remaining service period of the active employee group covered by the plans at the date of transition. The transitional asset relates to the pension plans and is the fair value of the plan assets less the accrued benefit obligation at October 1, 2000, amortized over 13 years. The transitional obligation relates to OPEB and is equal to the accrued benefit obligation at October 1, 2000, amortized over 15 years.

The regulated utility operations of the Company recover pension and OPEB expense based on the amounts paid. This is in accordance with the methodology accepted by the Regulators for rate-making purposes. As a result, rates typically only include the recovery of required contributions. A corresponding pension regulatory liability and OPEB regulatory asset have been recorded to the extent that they are expected to be included in regulator approved future rates and recovered from, or refunded to, future customers.

COMPARATIVE AMOUNTS
Certain comparative amounts have been reclassified to conform with the current year's consolidated financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES

Business Combinations
Effective January 1, 2011, the Company adopted Part V Section 1582, *Business Combinations,* which replaces Section 1581. The new standard requires assets and liabilities acquired in a business combination to be measured at fair value at the acquisition date and if applicable, any original equity interest in the investee to be re-measured to fair value through earnings on the date control is obtained. The standard also requires that acquisition-related costs, such as advisory or legal fees, incurred to effect a business combination be expensed in the period in which they are incurred. In accordance with the transitional provisions of this standard, Section 1582 was adopted prospectively and accordingly, assets and liabilities that arose from business combinations occurring before January 1, 2011 were not restated. The adoption of this standard has not impacted the Company's earnings, cash flows, or financial position for the year ended December 31, 2011.

Consolidated Financial Statements and Noncontrolling Interests
Effective January 1, 2011, the Company adopted Part V Sections 1601, *Consolidated Financial Statements*, and 1602, *Noncontrolling Interests*, which together replace the former consolidated financial statements standard. Under the revised standards, noncontrolling interests are classified as a component of equity, and earnings and comprehensive income are attributed to both the parent and non controlling interest. In accordance with the transitional provisions of these standards, Section 1601 was adopted prospectively and Section 1602 was adopted retroactively with restatement of prior periods. As the adoption of these standards impacts presentation only, there has been no impact to the Company's earnings, cash flows, or financial position for the current or prior periods presented.

United States Generally Accepted Accounting Principles (U.S. GAAP)
First-time adoption of Part I - International Financial Reporting Standards (Part I or IFRS) of The CICA Handbook was mandatory for Canadian publicly accountable enterprises on January 1, 2011, with the exception of certain qualifying entities. Part I applies to qualifying entities, including those with operations subject to rate regulation, for periods beginning on or after January 1, 2012. The Company is a qualifying entity for purposes of this deferral and has presented its consolidated financial statements in accordance with Part V of The CICA Handbook in the 2011 deferral period.

There continues to be uncertainty with respect to the application of IFRS to the rate regulated operations of the Company, which are pervasive and central to its business and performance measurement. The Company believes U.S. GAAP, which articulates specific guidance for entities subject to rate regulation, provides a more relevant basis on which to evaluate and present its regulated businesses. As a wholly-owned subsidiary of a United States Securities and Exchange Commission (SEC) registrant, the Company has received permission from the Canadian securities regulators to prepare its consolidated financial statements in accordance with U.S. GAAP and will adopt U.S. GAAP for interim and annual consolidated financial statements beginning on January 1, 2012.

3. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

For the purposes of this note, "Enbridge Gas Distribution" refers specifically to Enbridge Gas Distribution Inc. excluding St. Lawrence, whereas "St. Lawrence" refers specifically to St. Lawrence Gas Company, Inc.

RATE APPROVAL
Enbridge Gas Distribution's annual rates are currently set using a revenue per customer cap Incentive Regulation (IR) methodology. This IR methodology adjusts revenues, and consequently rates, annually and relies on an annual process to forecast volume and customer additions. Under IR, the Company has the opportunity to benefit from productivity enhancements and incremental revenues. The cost of natural gas is passed on to customers as a flow-through.

St. Lawrence's rates for each year are set using a Cost of Service (COS) methodology that allows the revenues to be set to recover forecast costs and to earn a rate of return on common equity. Forecast costs include natural gas commodity and transportation, operating and administrative, depreciation and amortization, municipal taxes, interest and income taxes. The rate base is the average level of investment in all recoverable assets used in natural gas distribution, storage and transmission and an allowance for working capital. Under COS, it is the responsibility of St. Lawrence to demonstrate to the NYSPSC the prudence of the costs incurred or to be incurred or the activities undertaken or to be undertaken. The cost of natural gas is passed on to customers as a flow-through.

APPROVED RATES

Enbridge Gas Distribution

Enbridge Gas Distribution's after-tax rate of return on common equity embedded in rates was 8.39% for the year ended December 31, 2011 (2010 - 8.39%) based on a 36% (2010 - 36%) deemed common equity component of capital for regulatory purposes.

To align the interests of customers with the Company's common shareholder, an earnings sharing mechanism forms part of the Settlement Agreement (the Settlement) with customer representatives approved by the OEB in February 2008. The Settlement encompasses all major financial aspects of the IR methodology that will operate for 2008 to 2012 (inclusive). To the extent the actual utility return on the approved equity level represented by normalized earnings (i.e., excluding the effects of weather) (ROE) exceeds the notional allowed utility return on equity (NROE) by certain prescribed thresholds, earnings are shared with customers. The common shareholder retains the first 100 basis points of ROE above the NROE, while earnings represented by the ROE in excess of 100 basis points above the NROE are shared equally with customers.

St. Lawrence

St. Lawrence's approved after-tax rate of return on common equity embedded in rates was 10.5% for the year ended December 31, 2011 (2010 - 10.5%) based on a 50% (2010 - 50%) deemed common equity component of capital for regulatory purposes. Any earnings above a return on equity of 11% (2010 - 11%) are shared equally with customers. The calculation of such earnings is cumulative over the three-year period commencing January 1, 2010 and ending December 31, 2012, and resulted in no sharing impact for the years ended December 31, 2011 and December 31, 2010.

IMPACTS OF RATE REGULATION

Regulatory Assets and Liabilities

As a result of rate regulation, the Company has recognized a number of regulatory assets and liabilities. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other. Long-term regulatory liabilities are recorded in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if the Company identifies an event indicative of possible impairment. In the absence of rate regulation, the Company would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Regulatory Risk and Uncertainties Affecting Recovery or Settlement

The recognition of regulatory assets and liabilities is based on the actions, or an expectation of the future actions, of the Regulators. To the extent that the Regulators' future actions are different from the Company's current expectations, the timing and amount of recovery or settlement of regulatory balances could differ from those recorded.

FINANCIAL STATEMENT EFFECTS

As a result of rate regulation, the following regulatory assets and liabilities have been recognized:

December 31,	**2011**	2010	Consolidated Statements of Financial Position Classification**	Estimated Recovery/ Settlement Period *(years)*	Earnings Impact[1] **2011**	Earnings Impact[1] 2010
(millions of Canadian dollars)						
Regulatory Assets/(Liabilities)						
Enbridge Gas Distribution						
Future income taxes [2]	**164**	164	DA/OLTL	*	**-**	(7)
OPEB [3]	**74**	68	DA	*	**4**	4
Unaccounted for gas variance [4]	**9**	18	AR	1	**(7)**	5
Settlement recoverable [5]	**5**	15	AR	1	**(7)**	(3)
Deferred rate hearing costs [6]	**3**	3	AR/DA	2	**-**	(2)
Future removal and site restoration reserves [7]	**(815)**	(753)	OLTL	*	**-**	-
Pension plans [8]	**(231)**	(222)	OLTL	*	**(6)**	(6)
Transactional services deferral [9]	**(7)**	(14)	AP	1	**-**	-
Earnings sharing deferral [10]	**(14)**	(38)	AP	1	**-**	-
Average use true-up variance [11]	**(3)**	4	AP/AR	*	**(5)**	1
Purchased gas variance [12]	**-**	(144)	AP	1	**-**	-
Shared Savings Mechanism [13]	**-**	11	AR	*	**-**	-
Other regulatory assets and liabilities	**2**	10	***	*	**(4)**	-
	(813)	(878)			**(25)**	(8)
St. Lawrence						
Other regulatory assets and liabilities	**6**	3	***	*	**2**	3
	6	3			**2**	3
	(807)	(875)			**(23)**	(5)

* Refer to the footnote for details.

**
AR – Accounts receivable and other
AP – Accounts payable and other
DA – Deferred amounts and other assets
OLTL – Other long-term liabilities

*** Dependent on the nature of the item.

1. *The earnings impact represents the increase/(decrease) in the Company's after-tax reported earnings as a result of the rate regulated recognition of the item, excluding any additional earnings sharing impact. This includes the impact of items outstanding at the end of the prior year being recovered or refunded in the current year.*

2. *The future income taxes balance represents the regulatory offset to future income tax liabilities to the extent that it is expected to be included in regulator-approved future rates and recovered from future customers. The recovery period depends on the timing of the reversal of temporary differences. In the absence of rate regulation, this regulatory balance and the related earnings impact would not be recorded.*

3. *The OPEB balance represents the regulatory offset to the OPEB liability to the extent that the amounts are to be collected from customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover OPEB expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and OPEB expense would be charged to earnings based on the accrual basis of accounting.*

4. *Unaccounted for gas variance represents the difference between the total natural gas distributed by Enbridge Gas Distribution and the amount of natural gas billed or billable to customers for their recorded consumption, to the extent it is different from the approved amount built into rates. Enbridge Gas Distribution has deferred unaccounted for gas variance and has historically been granted OEB approval for recovery or required refund of this amount in the subsequent year. In the absence of rate regulation, this variance would be included in earnings in the year incurred.*

5. *Settlement recoverable deferral represents amounts paid towards the settlement of a class action lawsuit related to late payment penalties. Pursuant to an OEB decision in February 2008, these amounts are being recovered from customers over a five-year period, which commenced in 2008. In the absence of rate regulation, these costs would be expensed as incurred.*

6. *Deferred rate hearing costs are incurred by Enbridge Gas Distribution for the regulatory process. Enbridge Gas Distribution has been granted OEB approval for recovery of such hearing costs, generally within two years. In the absence of rate regulation, these costs would be expensed as incurred.*

7. *Future removal and site restoration reserves result from amounts collected from customers by Enbridge Gas Distribution, with the approval of the OEB, to fund future costs for removal and site restoration relating to property, plant and equipment. These costs are collected as part of depreciation charged on property, plant and equipment. The balance represents the amount that Enbridge Gas Distribution has collected from customers, net of actual costs expended on removal and site restoration. The settlement of this balance will occur over the long-term as future removal and site restoration costs are incurred. In the absence of rate regulation, costs incurred for removal and site restoration would be charged to earnings as incurred with recognition of revenue for amounts previously collected.*

8. *The pension plans' balance represents the regulatory offset to the pension asset to the extent that the amounts are to be refunded to customers in future rates. The settlement period for this balance is not determinable. Enbridge Gas Distribution continues to record and recover pension expenditures through rates on a cash basis. In the absence of rate regulation, this regulatory balance would not be recorded and pension expense would be charged to earnings based on the accrual basis of accounting.*

9. *Transactional services deferral represents the customer portion of additional earnings generated from optimization of storage and pipeline capacity. Enbridge Gas Distribution has historically been required to refund the amount to customers in the following year. There would be no change in the treatment of this item in the absence of rate regulation.*

10. *Earnings sharing deferral represents amounts relating to the earnings sharing mechanism, which forms part of the IR Settlement. The earnings sharing is payable to customers and represents 50% of normalized earnings (i.e., excluding the effects of weather) represented by the ROE in excess of 100 basis points above the NROE. The December 31, 2011 balance relates to the years ended December 31, 2011 and 2010. The December 31, 2010 balance relates to the years ended December 31, 2010 and 2009. There would be no change in the treatment of this item in the absence of rate regulation.*

11. *Average use true-up variance represents the net revenue impact to be recovered from or refunded to customers, associated with any variance between forecast average use and actual normalized average use for general service customers. The amount will be recovered from or refunded to customers in future periods in accordance with the OEB's approval. In the absence of rate regulation, the variance would be included in earnings in the year incurred.*

12. *Purchased gas variance is the difference between the actual cost and the approved cost of natural gas reflected in rates. Enbridge Gas Distribution has been granted OEB approval to refund this balance to, or to collect this balance from, customers in the following quarter via the Quarterly Rate Adjustment Mechanism (QRAM) process. In the absence of rate regulation, the actual cost of natural gas would be included in gas commodity and distribution costs and revenues or costs would be adjusted by an equal and offsetting amount as the right to collect or refund the revenue or costs has been established.*

13. *Shared Savings Mechanism (SSM) deferral represents the benefit derived by Enbridge Gas Distribution as a result of its energy efficiency programs. Enbridge Gas Distribution has historically been granted OEB approval to recover the SSM amount through rates after a detailed review by the OEB. The process of review and subsequent recovery may extend over a few years. There would be no change in the treatment of this item in the absence of rate regulation.*

OTHER ITEMS AFFECTED BY RATE REGULATION

Revenue

To recognize the actions or expected actions of the Regulators, the timing and recognition of certain revenues and expenses may differ from that otherwise expected for non rate-regulated entities.

Operating Cost Capitalization

With the approval of the Regulators, the Company capitalizes a percentage of certain operating costs. The Company is authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. In the absence of rate regulation, a portion of such operating costs may be charged to earnings in the year incurred.

The Company entered into a service contract relating to asset management initiatives. The majority of the costs are being capitalized to gas mains in accordance with regulatory approval. At December 31, 2011, costs relating to this service contract of $133 million (2010 - $124 million) were included in gas mains and are being depreciated over the average service life of 25 years. In the absence of rate regulation, some of these costs would be charged to earnings in the year incurred.

Property, Plant and Equipment

In the absence of rate regulation, property, plant and equipment would not include some operating costs since these costs would have been charged to earnings in the period incurred. Further, on the retirement of utility assets, the excess of the book value net of proceeds would be recorded as a loss on the sale of assets in earnings in the period of retirement. Any removal costs incurred would be booked against the future removal and site restoration balance (described above).

Intangible Assets

The Company entered into contracts relating to CIS integration services, software maintenance and support. At December 31, 2011, the net book value of these costs was $99 million (2010 - $111 million). In the absence of rate regulation, a portion of the original cost of these assets would have been expensed in the period incurred.

Gas Inventories
Natural gas in storage is recorded in inventory at the prices approved by the Regulators in the determination of customers' system supply rates. In the absence of rate regulation, the actual price of natural gas purchased would be recorded in gas inventories.

Included in gas inventories at December 31, 2011 is $42 million (2010 - $43 million) of storage injection and demand costs. Consistent with the regulatory recovery pattern, these costs are recorded in gas inventories during the off-peak months and charged to gas costs during the peak winter months. In the absence of rate regulation, these costs would be expensed as incurred.

Depreciation
In the absence of rate regulation, depreciation rates would not have included a provision for future removal and site restoration costs.

4. ACQUISITION

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company. Project Amherstburg holds two solar projects, consisting of separate 10 megawatt (MW) and 5-MW facilities, both located in Amherstburg, Ontario. The total consideration transferred for the two projects was approximately $66 million, and was primarily funded by the issuance of common shares (1,612,367 shares). The remaining 0.1% limited partnership interest is owned by the general partner, Project AMBG2 Inc., a wholly-owned subsidiary of Enbridge Inc.

The transaction, which is a related party transaction, has been accounted for at carrying value. The Company consolidates its interest in Project Amherstburg.

Since the acquisition date, Project Amherstburg's revenue and earnings before tax for the year ended December 31, 2011 were $3 million and $2 million, respectively.

December 31,	**2011**
(millions of Canadian dollars)	
Carrying value of assets acquired:	
Property, plant and equipment	59
Intangible assets	9
Future income tax liability	(2)
	66
Consideration:	
Common shares	66

5. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Trade receivables	**378**	422
Unbilled revenues	**175**	231
Agent billing and collection receivable	**69**	86
Regulatory assets *(Note 3)*	**24**	61
Due from affiliates *(Note 20)*	**12**	11
Taxes receivable	**22**	14
Prepaid expenses	**3**	5
Other	**25**	23
Allowance for doubtful accounts	**(45)**	(51)
	663	802

6. PROPERTY, PLANT AND EQUIPMENT

December 31, 2011	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Regulated property, plant and equipment				
Gas mains	**4.2%**	**2,641**	**528**	**2,113**
Gas services	**4.5%**	**2,120**	**667**	**1,453**
Regulating and metering equipment	**3.7%**	**719**	**236**	**483**
Gas storage	**3.0%**	**275**	**89**	**186**
Land and right-of-way	**2.5%**	**79**	**30**	**49**
Computer technology	**19.8%**	**35**	**5**	**30**
Under construction	**-**	**92**	**-**	**92**
Construction materials inventory	**-**	**39**	**-**	**39**
Other	**3.5%**	**259**	**76**	**183**
		6,259	**1,631**	**4,628**
Unregulated property, plant and equipment				
Gas storage	**3.0%**	**88**	**4**	**84**
Solar assets	**4.0%**	**59**	**1**	**58**
		147	**5**	**142**
		6,406	**1,636**	**4,770**

December 31, 2010	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
(millions of Canadian dollars)				
Regulated property, plant and equipment				
Gas mains	4.2%	2,505	484	2,021
Gas services	4.6%	2,036	628	1,408
Regulating and metering equipment	3.8%	691	224	467
Gas storage	2.8%	240	79	161
Land and right-of-way	2.6%	77	29	48
Computer technology	19.8%	33	4	29
Under construction	-	66	-	66
Construction materials inventory	-	25	-	25
Other	3.5%	259	76	183
		5,932	1,524	4,408
Unregulated property, plant and equipment				
Gas storage	3.0%	52	2	50
		52	2	50
		5,984	1,526	4,458

Total depreciation expense, including amounts collected for future removal and site restoration costs, for property, plant and equipment was $250 million for the year ended December 31, 2011 (2010 - $238 million).

7. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory assets *(Note 3)*	**248**	252
Pension asset *(Note 18)*	**231**	222
Other	**10**	13
	489	487

8. INTANGIBLE ASSETS

December 31, 2011	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Regulated intangible assets				
Software	**20.0%**	**111**	**40**	**71**
CIS	**10.1%**	**127**	**28**	**99**
		238	**68**	**170**
Unregulated intangible assets				
Power purchase contract	**5.0%**	**9**	**-**	**9**
		9	**-**	**9**
		247	**68**	**179**

December 31, 2010	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Regulated intangible assets				
Software	20.1%	100	44	56
CIS	10.0%	127	16	111
		227	60	167

Intangible assets include $21 million of work-in-progress for the year ended December 31, 2011 (2010 - $9 million). Total amortization expense for intangible assets was $31 million for the year ended December 31, 2011 (2010 - $32 million).

9. ACCOUNTS PAYABLE AND OTHER

December 31,	**2011**	2010
(millions of Canadian dollars)		
Operating accrued liabilities	**250**	282
Regulatory liabilities *(Note 3)*	**32**	204
Budget billing plan payable	**136**	92
Security deposits	**79**	73
Dividends payable	**56**	54
Trade payables	**67**	57
Taxes payable	**26**	34
Interest payable	**26**	29
Due to affiliates *(Note 20)*	**10**	3
Current derivative liabilities *(Note 15)*	**1**	1
Other	**30**	21
	713	850

10. DEBT

December 31,	Weighted Average Interest Rate	Maturity	**2011**	2010
(millions of Canadian dollars)				
Debenture	9.85%	2024	**85**	235
Medium term notes	5.51%	2014-2050	**2,295**	2,195
Commercial paper and credit facility draws, net			**555**	333
Other			**8**	6
Deferred debt issue costs			**(13)**	(20)
Total debt			**2,930**	2,749
Current maturities			**-**	(150)
Short-term borrowings	1.07%		**(556)**	(332)
Long-term debt			**2,374**	2,267
Loans from affiliate company			**375**	375

Medium term note maturities for the years ending December 31, 2012 through 2016 are nil, nil, $400 million, nil, and nil, respectively. The Company's debenture and medium term notes bear interest at fixed rates and the interest obligations for the years ending December 31, 2012 through 2016 are $135 million, $135 million, $129 million, $114 million and $114 million, respectively.

INTEREST EXPENSE

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Debenture and medium term notes	**140**	149
Loans from affiliate company *(Note 20)*	**27**	27
Commercial paper and credit facility draws	**3**	2
Other interest and finance costs	**8**	11
Capitalized	**(6)**	(3)
	172	186

In 2011, total interest paid to third parties was $149 million (2010 - $158 million) and total interest paid to affiliated companies was $20 million (2010 - $27 million).

CREDIT FACILITIES

The Company currently has a $700 million commercial paper program limit that is backstopped by committed lines of credit of $700 million. The term of any commercial paper issued under this program may not exceed one year. The Company has the option, at its discretion, to extend the maturity date of the committed lines of credit for an additional year.

December 31, 2011	Total Facilities	Credit Facility Draws[1]	Available
(millions of Canadian dollars)			
Enbridge Gas Distribution Inc.	**700**	**545**	**155**
St. Lawrence Gas Company, Inc.	**12**	**10**	**2**
Total credit facilities	**712**	**555**	**157**

1. Includes facility draws and commercial paper issuances, net of discount, that are backstopped by the credit facility.

Credit facilities carried a weighted average standby fee of 0.38% per annum from January to July 2011 and 0.22% per annum from August to December 2011 on the unused portion and draws bear interest at market rates.

11. OTHER LONG-TERM LIABILITIES

December 31,	**2011**	2010
(millions of Canadian dollars)		
Regulatory liabilities *(Note 3)*	**1,047**	984
OPEB liabilities *(Note 18)*	**75**	71
Pension liability *(Note 18)*	**5**	3
	1,127	1,058

12. SHARE CAPITAL

The authorized share capital of the Company consists of an unlimited number of common shares with no par value and a limited number of preferred shares.

COMMON SHARES

December 31,	**2011**		2010	
	Number of Shares	**Amount**	Number of Shares	Amount
(millions of Canadian dollars; number of common shares in millions)				
Balance at beginning of year	**140.7**	**1,071**	140.7	1,071
Common shares issued	**1.6**	**66**	-	-
Balance at end of year	**142.3**	**1,137**	140.7	1,071

PREFERRED SHARES

December 31, 2011 and 2010	Authorized	Issued and Outstanding	Amount
(millions of Canadian dollars, number of preferred shares in millions)			
Group 1	0.2	nil	-
Group 2, Series A - C, Cumulative Redeemable Retractable	6	nil	-
Group 2, Series D, Cumulative Redeemable Convertible	4	nil	-
Group 3, Series A - C, Cumulative Redeemable Retractable	6	nil	-
Group 3, Series D, Fixed / Floating Cumulative Redeemable Convertible	4	4	100
Group 4	10	nil	-
Group 5	10	nil	-
			100

Floating adjustable cumulative cash dividends on the Group 3, Series D preferred shares are payable at 80% of the prime rate. The Company has the option to redeem the shares for $25.50 per share if the preferred shares are publicly traded, and for $25.00 per share in all other circumstances, together with accrued and unpaid dividends in each case.

On July 1, 2014, and every five years thereafter, the Group 3, Series D preferred shares can be converted, at the holder's option, into Group 2, Series D preferred shares, on a one-for-one basis, and will pay fixed cumulative cash dividends that are not less than 80% of the Government of Canada yield applicable to the fixed dividend period.

The Group 2, Series D preferred shares can be redeemed, at the Company's option, for $25.00 per share. The Group 2, Series D preferred shares can also be converted into Group 3, Series D preferred shares on a one-for-one basis at the holder's option on July 1, 2014 and every five years thereafter.

13. STOCK OPTION AND STOCK UNIT PLANS

Certain employees and senior officers of the Company are granted stock-based compensation from Enbridge through its three long-term incentive compensation plans: the Incentive Stock Option (ISO) Plan, the Performance Stock Unit (PSU) Plan and the Restricted Stock Unit (RSU) Plan. The PSU and RSU plans grant notional units as if a unit were one Enbridge common share and are payable in cash.

INCENTIVE STOCK OPTIONS
Key employees are granted ISOs to purchase common shares of Enbridge at the market price on the grant date. ISOs vest in equal annual installments over a four-year period and expire 10 years after the issue date.

During the year ended December 31, 2011, 663,800 stock options (2010 - 361,000 stock options) were issued to employees of the Company. The stock options were issued at a weighted average exercise price of $28.78 in 2011 (2010 - $23.30) and a grant date fair value of $4.00 (2010 - $3.28).

PERFORMANCE STOCK UNITS
Enbridge has a PSU Plan that includes the Company's senior officers where cash awards are paid following a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by Enbridge's weighted average common share price and by a performance multiplier. The performance multiplier ranges from zero, if Enbridge's performance fails to meet threshold performance levels, to a maximum of two, if Enbridge performs within the highest range of its performance targets. The 2009, 2010, and 2011 grants derive the performance multiplier through a calculation of Enbridge's price/earnings ratio relative to a specified peer group of companies and Enbridge's growth in earnings per share, adjusted for non-operating or non-recurring items, relative to targets established at the time of grant.

During the year ended December 31, 2011, 25,200 PSUs (2010 - 18,200) were issued to employees of the Company.

RESTRICTED STOCK UNITS
Enbridge has an RSU plan where cash awards are paid to certain non-executive employees of the Company following a 35 month maturity period. RSU holders receive cash equal to Enbridge's weighted average share price multiplied by the units outstanding on the maturity date.

During the year ended December 31, 2011, Enbridge granted 111,300 RSUs (2010 - 124,000) to certain employees of the Company.

STOCK-BASED COMPENSATION EXPENSE
The Company is charged an expense for stock-based compensation which includes a direct charge for ISOs, PSUs and RSUs issued to employees of the Company and an allocation of such costs with respect to employees of Enbridge who provide services to the Company. For the year ended December 31, 2011, the total amount of direct charge was $8 million (2010 - $6 million) and the total amount of allocation was $6 million (2010 - $5 million). These costs are included in operating and administrative expenses.

14. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

MARKET PRICE RISK
The Company's earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and natural gas prices (collectively, market price risk). Portions of these risks are borne by customers through certain regulatory mechanisms. Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Company is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk
The Company's earnings and cash flows are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily commercial paper. Floating to fixed interest rate swaps and options are

used to hedge against the effect of future interest rate movements. The Company has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2012 at an average rate of 1.8%.

At December 31, 2011, a 1% increase across the interest rate yield curve at that date, with all other variables constant, would have resulted in no change (2010 - nil) in earnings and would have caused a $1 million increase (2010 - $3 million) in OCI in the year due to the revaluation of interest rate derivatives outstanding at December 31, 2011, and a $6 million decrease (2010 - $3 million) in earnings due to increased interest expense related to the Company's variable rate debt outstanding at December 31, 2011 assuming the variable rate debt outstanding had been outstanding for the entire period.

Foreign Exchange Risk

Foreign exchange risk is the risk of gains and losses due to the volatility of currency exchange rates. A portion of the Company's purchases of natural gas are denominated in United States dollars and as a result there is exposure to fluctuations of the United States dollar against the Canadian dollar. Realized foreign exchange gains or losses relating to natural gas purchases are passed on to the customer; therefore, the net exposure of the Company to movements in the foreign exchange rate on natural gas purchases is nil (2010 - nil).

Natural Gas Price Risk

Natural gas price risk is the risk of gain or loss due to changes in the market price of natural gas. Only St. Lawrence manages the exposure to natural gas price risk by entering into fixed price natural gas contracts. Other than St. Lawrence, the Company no longer manages natural gas price risk exposure, in compliance with the directive of the OEB. Fluctuations in natural gas prices are borne by the customers.

TOTAL DERIVATIVE INSTRUMENTS

The total notional principal or quantity outstanding related to the Company's derivative instruments at December 31, 2011 include $111 million of interest rate contracts and 6 million cubic metres of natural gas contracts, both maturing in 2012.

The Company does not have any credit-risk related contingent features associated with its derivative instruments.

The Company estimates that $1 million of AOCL related to cash flow hedges from interest rate contracts will be reclassified to earnings in the next 12 months. Actual amounts reclassified to earnings depend on the interest rates in effect when derivative contracts that are currently outstanding mature. Any gains or losses from natural gas derivatives are borne by customers. For all forecasted transactions, the maximum term over which the Company is hedging exposures to the variability of cash flows is 24 months at December 31, 2011.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations, including commitments *(Notes 20 and 21)*, as they become due. In order to manage this risk, the Company forecasts cash requirements over a twelve month rolling time period to determine whether sufficient funds will be available. The Company's primary sources of liquidity and capital resources are funds generated from operations and the issuance of commercial paper and/or credit facility draws. The Company maintains a current shelf prospectus with the securities regulators, which enables, subject to market conditions, ready access to the Canadian public capital markets. In addition, the Company maintains sufficient liquidity through committed credit facilities *(Note 10)* with a diversified group of banks and institutions which, if necessary, enables the Company to fund all anticipated requirements for one year without accessing the capital markets. The Company is in compliance with all the terms and conditions of its committed credit facilities at December 31, 2011. As a result, all credit facilities are available to the Company and the banks are obligated to fund, and have been funding, the Company under the terms of the facilities.

Maturities of Financial Instruments

The Company generally has no financial instruments, other than derivative instruments, maturing beyond one year with the exception of its long-term debt and loans from affiliate company *(Notes 10 and 20)*.

Based on valuations at December 31, 2011, the Company's financial derivative instruments will give rise to $1 million undiscounted cash outflows in 2012.

CREDIT RISK

The Company is exposed to credit risk from accounts receivable and derivative financial instruments. Exposure to credit risk is largely mitigated by the large and diversified customer base and the ability to recover an estimate for doubtful accounts for utility operations through the rate-making process. The Company actively monitors the financial strength of large industrial customers and, in select cases, has tightened credit terms including obtaining additional security to minimize the risk of default on receivables. Generally, the Company classifies and provides for receivables older than 30 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed in Note 15, *Fair Value of Financial Instruments*.

The change in the allowance for doubtful accounts with respect to accounts receivable is detailed below.

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Balance at beginning of year	**(51)**	**(57)**
Additional allowance	**(25)**	**(23)**
Amounts used and reversed	**31**	**29**
Balance at end of year	**(45)**	**(51)**

The Company's policy requires that customers settle their billings in accordance with the payment terms listed on their bill, which is generally within 21 days. A provision for credit and recovery risk associated with accounts receivable has been made through the allowance for doubtful accounts.

The allowance for doubtful accounts is determined based on collection history. When the Company has determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

Estimated costs associated with uncollectible accounts receivable are recovered through regulated distribution rates, which largely limits the Company's exposure to credit risk related to accounts receivable, to the extent such estimates are accurate. Under IR, these estimated costs recovered through distribution rates relate to the base year of the IR plan (2007) and are escalated by the approved formula during the IR term.

Entering into derivative financial instruments can also result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company only enters into risk management transactions with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, frequent assessment of counterparty credit ratings and netting arrangements.

The Company generally has a policy of entering into individual International Securities Dealers Association agreements, or other similar derivative agreements, with the majority of our derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with those specific counterparties in the event of bankruptcy or other significant credit event, and would reduce our credit risk exposure on derivative asset positions outstanding with these counterparties in these particular circumstances.

At December 31, 2011, the Company has a maximum exposure to credit risk of nil (2010 - nil) related to its derivative counterparties.

15. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table summarizes the Company's financial instrument carrying and fair values and provides a reconciliation to the Consolidated Statements of Financial Position.

December 31, 2011	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	9	-	-	-	-	-	9	9
Accounts receivable and other	-	-	614	-	-	49	663	614
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	7	-	-	-	-	-	7	7
Short-term borrowings	-	-	-	556	-	-	556	556
Accounts payable and other	-	-	-	654	1	58	713	655
Long-term debt	-	-	-	2,374	-	-	2,374	2,943
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

December 31, 2010	Held for Trading	Available for Sale	Loans and Receivables	Other Financial Liabilities	Qualifying Hedging Derivatives	Non-Financial Instruments	Total	Fair Value[1]
(millions of Canadian dollars)								
Assets								
Cash and cash equivalents	13	-	-	-	-	-	13	13
Accounts receivable and other	-	-	722	-	-	80	802	722
Investment in affiliate company[2]	-	825	-	-	-	-	825	N/A
Liabilities								
Bank overdraft	17	-	-	-	-	-	17	17
Short-term borrowings	-	-	-	332	-	-	332	332
Accounts payable and other	-	-	-	611	1	238	850	612
Long-term debt	-	-	-	2,417	-	-	2,417	2,775
Loans from affiliate company[2]	-	-	-	375	-	-	375	N/A

1. *Fair value does not include non-financial instruments and available for sale equity instruments held at cost that do not trade on an actively quoted market (Note 20).*
2. *Investment in affiliate company and loans from affiliate company resulted from related party transactions and are carried at historical cost; no fair value has been determined (Note 20).*

The fair value of financial instruments reflects the Company's best estimates of fair value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Company uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value. The fair value of financial instruments other than derivatives represents the amounts estimated to be received from or paid to counterparties to settle these instruments at the reporting date.

The fair value of Cash and cash equivalents and Short-term borrowings approximates their carrying value due to their short-term maturities. The fair value of the Company's long-term debt is based on quoted market prices for instruments of similar yield, credit risk and tenure. The fair value of other financial assets and liabilities other than derivative instruments approximate their cost due to the short period to maturity. Changes in the fair value of financial liabilities other than derivative instruments are due primarily to fluctuations in interest rates, natural gas prices and time value.

FAIR VALUE OF DERIVATIVES

The Company categorizes its derivative assets and liabilities, measured at fair value, into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1
Level 1 includes derivatives measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a derivative is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2
Level 2 includes derivative valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Derivatives in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the derivative. Derivatives valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps and natural gas swaps for which observable inputs can be obtained.

Level 3
Level 3 includes derivative valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the derivatives' fair value. Generally, Level 3 derivatives are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available, or have no binding broker quote to support Level 2 classification. The Company has developed methodologies, benchmarked against industry standards, to determine fair value for these derivatives based on extrapolation of observable future prices and rates.

When possible the estimated fair value is based on quoted market prices, and, if not available, estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Company uses standard valuation techniques to calculate fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes pricing models for options. Depending on the type of derivative and the nature of the underlying risk, primary inputs to these techniques include observable market prices (interest, foreign exchange and natural gas) and volatility. The Company uses inputs and data used by willing market participants when valuing derivatives and considers its own credit default swap spread as well as those of its counterparties in its determination of fair value. Where possible, the Company uses observable inputs.

At December 31, 2011, the Company has current Level 2 derivative liabilities with fair value of $1 million (2010 - $1 million).

16. CAPITAL DISCLOSURES

The Company defines capital as shareholders' equity (excluding AOCL), long-term debt (including intercompany debt, excluding transaction costs), short-term borrowings, cash and cash equivalents and bank overdraft.

The Company's capital is calculated as follows:

December 31,	**2011**	2010
(millions of Canadian dollars)		
Cash and cash equivalents	**(9)**	(13)
Bank overdraft	**7**	17
Short-term borrowings	**556**	332
Long-term debt (includes current portion)	**2,387**	2,437
Loans from affiliate company	**375**	375
Shareholders' equity	**2,000**	1,945
	5,316	5,093

The Company's objectives when managing capital are to maintain flexibility among: enabling the business to operate at the highest efficiency while maintaining safety and reliability; providing liquidity for growth opportunities; maintaining a capital structure that is in alignment with the deemed equity ratio of 36%; and providing acceptable returns to the common shareholder. These objectives are primarily met through maintenance of an investment

grade credit rating, which provides access to lower cost capital. Capital is available generally through the issuance of both short and long-term debt and equity.

The Company manages its capital in light of changes in the economic and regulatory environment and the underlying assets. In order to maintain or adjust the capital structure, the Company may adjust the amount of dividends paid to the common shareholder, issue new shares or issue new debt. Dividend payments are determined with the objective of maintaining a capital structure that is in alignment with the deemed equity ratio of 36%.

Due to the seasonal nature of the Company's business and continuing growth in the asset base, cash receipts do not typically match the Company's requirements for capital expenditures, dividends, long-term debt retirement and inventory replenishment. Generally, cash shortfalls are financed initially through the issuance of short-term debt. The Company maintains a balanced capital structure by periodically refinancing short-term debt with long-term debt.

The Company's borrowings, whether debentures or medium term notes, are unsecured. When issuing any new indebtedness with a maturity of over 18 months, covenants contained in the Company's trust indentures require that the pro forma long-term debt interest coverage ratio be at least 2.0 times for twelve consecutive months out of the previous 23 months. The pro forma long-term debt interest coverage ratio is calculated as Canadian GAAP earnings adjusted for income taxes, long-term debt interest expense, amortization of debt issue costs and intercompany interest expense, less gains on asset dispositions divided by the annual interest requirements. The Company is permitted to refinance maturing long-term debt with a matching long-term debt issue without the requirement to meet the 2.0 times interest coverage test. As at December 31, 2011, the Company was in compliance with these covenants.

17. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Earnings before income taxes	**262**	254
Combined statutory income tax rate	**28.3%**	31.0%
Income taxes at statutory rate	**74**	79
Increase/(decrease) resulting from:		
Non-taxable dividend income from affiliated companies	**(18)**	(19)
Future income taxes related to regulated operations	**-**	7
Other	**(5)**	(6)
Income taxes	**51**	61
Effective income tax rate	**19.5%**	24.0%

The future income taxes recorded in current liabilities of $2 million (2010 - $5 million) arise primarily from temporary differences relating to regulatory deferral accounts.

At December 31, 2011, the Company had a future income tax liability of $164 million (2010 - $164 million) related to regulatory assets, primarily property, plant and equipment, with an offsetting long-term regulatory asset *(Note 3)* to the extent that the future income tax liability is expected to be included in regulator-approved future rates and recovered from future customers.

18. POST-EMPLOYMENT BENEFITS

PENSION PLANS

The Company provides a non-contributory basic pension plan that provides either defined benefit and/or defined contribution pension benefits to the majority of its employees. The Company has two supplemental non-contributory defined benefit pension plans which provide pension benefits in excess of the basic plan for certain

employees. A measurement date of December 31, 2011 was used to determine the plan assets and the accrued benefit obligation.

Defined Benefit Plans
Benefits payable from the defined benefit plans are based on members' years of service and final average remuneration. These benefits are partially inflation indexed after a member's retirement. Contributions by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective date of the most recent actuarial valuation was December 31, 2009, and the effective date of the next required actuarial valuation is December 31, 2012.

The defined benefit pension plan costs have been determined based on management's best estimates and assumptions of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans
Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution plans, benefit costs equal amounts required to be contributed by the Company.

Post-employment Benefits Other than Pensions
OPEB primarily include supplemental health, dental, health spending account and life insurance coverage for qualifying retired employees.

DEFINED BENEFIT PLANS
The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability for the Company's defined benefit pension plans and OPEB plan using the accrual method.

	Pension Benefits		OPEB	
December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Change in accrued benefit obligation				
Benefit obligation at beginning of year	**702**	588	**87**	81
Service cost	**16**	12	**1**	1
Interest cost	**39**	39	**5**	5
Actuarial loss	**127**	79	**13**	5
Benefits paid	**(33)**	(31)	**(3)**	(3)
Other	**1**	15	**-**	(2)
Benefit obligation at end of year	**852**	702	**103**	87
Change in plan assets				
Fair value of plan assets at beginning of year	**759**	695	**4**	-
Transfer to the defined contribution component	**(1)**	(2)	**-**	-
Actual return on plan assets	**15**	78	**-**	-
Employer's contributions	**4**	4	**6**	7
Benefits paid	**(33)**	(31)	**(3)**	(3)
Other	**-**	15	**(1)**	-
Fair value of plan assets at end of year	**744**	759	**6**	4
Funded status				
Benefit obligation	**(852)**	(702)	**(103)**	(87)
Fair value of plan assets	**744**	759	**6**	4
Overfunded/(underfunded) status at end of year	**(108)**	57	**(97)**	(83)
Unamortized prior service cost	**2**	4	**-**	-
Unamortized transitional (asset)/obligation	**(44)**	(70)	**13**	16
Unamortized net actuarial loss/(gain)	**376**	228	**9**	(4)
Net amount recognized in the Consolidated Statements of Financial Position at end of year	**226**	219	**(75)**	(71)
Included in the following accounts:				
Deferred amounts and other assets *(Note 7)*	**231**	222	**-**	-
Other long-term liabilities *(Note11)*	**(5)**	(3)	**(75)**	(71)

The weighted average assumptions made in the measurement of the projected benefit obligations of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Discount rate	**4.50%**	5.70%	**4.50%**	5.70%
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	**5.00%**

Net Benefit Costs Recognized

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Benefits earned during the year	**16**	12	**1**	1
Interest cost on projected benefit obligations	**39**	39	**5**	5
Actual return on plan assets	**(15)**	(78)	**-**	-
Actuarial loss	**127**	79	**13**	5
Differences between costs arising in the year and costs recognized in the year:				
Return on plan assets	**(38)**	29	**-**	-
Prior service costs	**2**	1	**-**	-
Transitional (asset)/obligation	**(26)**	(24)	**3**	3
Actuarial loss	**(110)**	(64)	**(13)**	(5)
Net defined benefit costs on an accrual basis	**(5)**	(6)	**9**	9
Defined contribution benefit costs	**1**	2	**-**	-
(Credits)/costs on an accrual basis	**(4)**	(4)	**9**	9

Costs related to the period on an accrual basis are presented above and are initially expensed. However, there is a partially offsetting adjustment due to the regulatory mechanism in place. As a result, the net expense, which is consistent with the recovery of such costs in rates, was $4 million for pension benefits and $4 million for OPEB for the year ended December 31, 2011 (2010 - $4 million and $4 million, respectively).

The weighted average assumptions made in the measurement of the cost of the pension plans and OPEB are as follows:

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
Discount rate	**5.70%**	6.60%	**5.70%**	6.60%
Average rate of return on pension plan assets	**7.25%**	7.14%	**-**	-
Average rate of salary increases	**3.50%**	3.50%	**5.00%**	5.00%

MEDICAL COST TRENDS

The assumed rates for the next year used to measure the expected cost of benefits are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in Which Ultimate Medical Cost Trend Rate Assumption is Achieved
Drugs	8.40%	4.50%	2029
Other Medical and Dental	4.50%	4.50%	2029

A 1% increase in the assumed medical and dental care trend rate would result in an increase of $15 million in the accumulated post-employment benefit obligations and an increase of $1 million in benefit and interest costs. A 1% decrease in the assumed medical and dental care trend rate would result in a decrease of $12 million in the accumulated post-employment benefit obligations and a decrease of $1 million in benefit and interest costs.

PLAN ASSETS

Major Categories of Plan Assets

	Pension Benefits		
	2011		2010
As at December 31,	Allocation	Amount	Allocation
(millions of Canadian dollars)			
Equity securities	**55%**	**410**	58%
Fixed income securities	**44%**	**328**	41%
Other	**1%**	**7**	1%
Total assets	**100%**	**745**	100%

The Company manages the investment risk of its defined benefit pension plans by setting a long-term asset mix policy for each plan after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plan; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Target Mix for Plan Assets	
Equity securities	52.5%
Fixed income securities	42.5%
Other	5.0%

PLAN CONTRIBUTIONS BY THE COMPANY

	Pension Benefits		OPEB	
Year ended December 31,	**2011**	2010	**2011**	2010
(millions of Canadian dollars)				
Total contributions	**4**	4	**6**	7
Contributions expected to be paid in 2012	**20**		**4**	

BENEFITS EXPECTED TO BE PAID BY THE COMPANY

Year ended December 31,	2012	2013	2014	2015	2016	2017-2021
(millions of Canadian dollars)						
Expected future benefit payments	39	41	43	45	47	255

19. CASH FLOW INFORMATION

CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
Accounts receivable and other	**139**	8
Gas inventories	**20**	(4)
Accounts payable and other	**(142)**	41
	17	45

SIGNIFICANT NON-CASH ITEMS

In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares.

20. RELATED PARTY TRANSACTIONS

Year ended December 31,	**2011**	2010
(millions of Canadian dollars)		
IPL System Inc.		
Dividend income	**63**	63
Interest expense	**27**	27
Enbridge Inc.		
Purchase of treasury and other management services	**34**	32
Gazifère Inc.		
Revenue from wholesale service, including gas sales	**28**	30
Vector Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**24**	27
Vector Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**2**	1
Alliance Pipeline Limited Partnership (Canadian)		
Purchase of gas transportation services	**25**	25
Alliance Pipeline Limited Partnership (U.S.)		
Purchase of gas transportation services	**18**	17
Enbridge Commercial Services Inc.		
Purchase of information services	**-**	2

The Company had related party balances as follows:

December 31,	**2011**	2010
(millions of Canadian dollars)		
Investment in affiliate company		
IPL System Inc.	**825**	825
Dividend receivable	**5**	5
Loans from affiliate company		
IPL System Inc.	**375**	375
Interest payable	**9**	2
Note payable to affiliate company		
Enbridge (U.S.) Inc.	**8**	6
Accounts receivables/(payables)		
Enbridge Inc.	**(1)**	(1)
Gazifère Inc.	**4**	5
Niagara Gas Transmission Ltd.	**2**	-

Financing Transactions

The Company has invested in Class D, non-voting redeemable, retractable preferred shares of IPL System Inc., an affiliate under common control. At December 31, 2011, the investment of $825 million (2010 - $825 million) in these shares, at cost, resulted in a weighted average dividend yield of 7.60%.

At December 31, 2011, the borrowing from IPL System Inc. stood at $375 million ($200 million at 6.85% and $175 million at 7.50%). These loans are repayable in 2049 and 2051, respectively. The Company may elect to defer interest payments on the loans for up to five years and settle deferred interest in either cash or non-retractable

preferred shares of the Company. For the year ended December 31, 2011, interest paid amounted to $20 million (2010 - $27 million).

The note payable to Enbridge (U.S.) Inc. bears interest at the LIBOR rate plus 0.55% and is payable on demand.

Treasury and Other Management Services
Enbridge provides treasury and other management services and charges the Company amounts designed to recover the costs of providing such services.

Wholesale Service
These services are pursuant to a contract negotiated between the Company and Gazifère Inc., an affiliate under common control, and approved by the OEB and Gazifère Inc.'s regulator, the Régie de l'énergie.

Gas Transportation Services
The Company has contracted for natural gas transportation services from Vector Pipeline Limited Partnership (U.S.), Vector Pipeline Limited Partnership (Canadian), Alliance Pipeline Limited Partnership (Canadian) and Alliance Pipeline Limited Partnership (U.S.), related entities partially owned by an affiliated company under common control. Contractual obligations under these contracts are 2012 - $69 million, 2013 to 2014 - $131 million, 2015 to 2016 - $70 million and thereafter - nil.

Information Services
The Company purchases access to a few of its customer care information systems from Enbridge Commercial Services Inc. (ECS), an affiliate under common control. ECS charges the Company amounts under a service level agreement designed to recover the cost of providing the service.

Trade Receivables and Payables
The cash balances of the Company and its subsidiaries are subject to a concentration banking arrangement with Enbridge. Interest is received or paid at market rates.

The Company provides consulting and other services to affiliates. Market prices are charged for these services where they are reasonably determinable. Where no market price exists, a cost-based price is charged. The Company may also purchase consulting and other services from affiliates with prices determined on the same basis as services provided by the Company. The trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

Other Transactions
In August 2011, the Company's parent transferred a 99.9% limited partnership interest in Project Amherstburg to the Company for non-cash consideration of $66 million, primarily funded by the issuance of common shares *(Note 4)*.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

21. COMMITMENTS AND CONTINGENCIES

COMMITMENTS
The Company has entered into long-term contracts and future payments under the contracts are as follows:

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Services contract [1]	15	7	8	-	-
Customer care service contracts [2]	359	58	115	122	64
Total	374	65	123	122	64

1. *Primarily fees relating to services provided with respect to work and asset management initiatives. The majority of these expenditures will be capitalized to gas mains under property, plant and equipment in accordance with regulatory treatment. At December 31, 2011, $133 million (2010 - $124 million) of such costs were included in gas mains, which are depreciated over the average service life of 25 years.*
2. *In 2011, the Company's Board of Directors approved a five-year nine month extension, beginning in 2012, to the Company's customer care services contract with a third party service provider. The total cost of the customer care services during the term of the extension is approximately $360 million. The OEB approved the Company's recovery of costs associated with the agreement in 2011.*

CONTINGENCIES

Former Manufactured Coal Gas Plant Sites

The remediation of discontinued manufactured gas plant (MGP) sites may result in future costs. The Company was named as a defendant in ten lawsuits issued in 1991 and 1993 in the Ontario Court of Justice (General Division), commenced by the Corporation of the City of Toronto (the City). Two additional actions were commenced by the Toronto Board of Education (the School Board) in 1991. In these actions, the City and the School Board claimed damages totaling approximately $79 million for alleged contamination of lands acquired by the City for the purposes of its Ataratiri housing project. The City alleges that these lands are contaminated by coal tar deposited on the properties during a time when all or a portion of such lands were utilized by the Company for the operation of its Station A MGP.

While these Statements of Claim were issued by the City and the School Board, they were never formally served on the Company. It was and remains the Company's understanding that these lawsuits were initiated, at least in part, because of concerns that the passage of time might give rise to limitation period defences. Rather than litigate, the Company and the City entered into an agreement (known as a Tolling Agreement) pursuant to which the City and the School Board agreed to forbear from serving the Statements of Claim pending further discussions with the Company. To the knowledge of the Company, neither the City nor the School Board has taken any steps to advance the lawsuits.

On August 30, 1994, Wyndham Court Canada Inc. (Wyndham) commenced an action in the Ontario Court of Justice (General Division) against the Company and 20 other defendants claiming that coal tar originating from the Company's Station A MGP in Toronto migrated to lands owned by Wyndham. Wyndham claimed general damages in the amount of $70 million and punitive damages in the amount of $5 million. It is believed that this action was also commenced by Wyndham due to its concern about the running of limitation periods.

The Company entered into a Tolling Agreement with Wyndham pursuant to which Wyndham's action was discontinued, without prejudice to Wyndham's right to commence a similar action in the future. In the fall of 2002, the Company received notice that Wyndham sold the lands that were the subject of the action to Cityscape Holdings Inc., which directed that title to a portion of these lands be transferred to Cityscape Residential Inc. (jointly Cityscape). Cityscape served the Company with a Statement of Claim in February 2003, naming the Company and nine other defendants who own or have owned portions of the former Station A MGP site. Cityscape is claiming $50 million in damages and $5 million in punitive damages against the Company as a result of alleged coal tar contamination of the lands now owned by Cityscape. The Company responded with a Statement of Defence denying liability. In January 2004, Cityscape dismissed the action against each of the Company's co-defendants.

In February 2008, the Ontario Superior Court of Justice ordered that examinations for discovery of the plaintiff be completed by mid-June 2008. Examinations for discovery were completed by this date, but required steps in the discovery process have not yet been completed by the plaintiff. At present, it is unknown when the trial of the matter will be heard.

The Company has put all of its known existing and subsisting former third party liability insurers on notice of the Cityscape action. To date, no insurer has confirmed that insurance coverage exists, nor has any insurer acknowledged that it owes the Company a duty to defend the Cityscape lawsuit. The Company first advised the OEB of the Cityscape action during its fiscal 2003 Rate Case and sought approval for a manufactured gas plant deferral account to record the costs of investigating, defending and dealing with the Cityscape action and any future MGP claims that may be advanced. With respect to the Company's 2006 to 2012 fiscal years, the OEB approved the establishment of deferral accounts. The issue of whether the possible claims and related costs are recoverable from customers has yet to be determined.

The Company remains of the view that it has a valid defence to the Cityscape lawsuit; however, it acknowledges that certain risks exist. Given the novel nature of such environmental claims, the law as it relates to such claims is not settled. Should remediation of former MGP sites be required, it may result in future costs, the quantum of which cannot be determined at this time for several reasons. First, there is no certainty about the presence of and the extent of alleged coal tar contamination at or near former MGP sites. Second, there are a number of potential alternative remediation/isolation/containment approaches, which could vary widely in cost.

Although there are no known regulatory precedents in Canada, there are precedents in the United States for the recovery in rates of costs relating to the remediation of former MGP sites. The Company expects that if it is found that it must contribute to any remediation costs (either as a result of a lawsuit or government order), it would be generally allowed to recover in rates those costs not recovered through insurance or by other means. Accordingly, the Company believes that the ultimate outcome of these matters will not have a significant impact on the Company's financial position.

Bloor Street Incident

The Company was charged under both the Ontario Technical Standards and Safety Act (TSSA) and the Ontario Occupational Health and Safety Act (OHSA) in connection with an explosion that occurred in April 2003 on Bloor Street West in Toronto. In December 2011, the Company pleaded guilty before the Ontario Court of Justice to one charge under OHSA and one charge under TSSA. The Court imposed a fine of $350,000 in connection with each charge. With the application of a required 25% Victim Fine Surcharge, the total amount payable by the Company was $875,000.

OTHER LITIGATON

The Company is subject to various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on the Company's consolidated financial position or results of operations.

CORPORATE INFORMATION

TRUSTEE AND REGISTRARS

Debenture
9.85% debenture

CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6
and in Montreal, Calgary and Vancouver

For the above debenture, CIBC Mellon Trust Company of Canada is the Interest Dispersing Agent.

REGISTRAR AND PAYING AGENT

Medium Term Notes
Canadian Imperial Bank of Commerce
Debt Management Service
22 Front Street West, 5th Floor
Toronto, Ontario, M5J 2W5

TRUSTEE

Medium Term Notes
CIBC Mellon Trust Company of Canada
c/o BNY Mellon Trust Company of Canada
Corporate Trust Services
320 Bay Street, 11th Floor
Toronto, Ontario, M5H 4A6

REGISTRAR AND TRANSFER AGENT

Group 3 Preferred Shares
Computershare Investor Services Inc.
100 University Avenue
Toronto, Ontario, M5J 2Y1

CORPORATE GOVERNANCE

The size of the Board of Directors of the Company is currently set at six (6) members, two (2) of whom are considered to be independent directors.

The Board has an Audit, Finance & Risk Committee comprised of the following directors:

J. L. Braithwaite
D.A. Leslie
J. R. Bird

The Audit, Finance & Risk Committee's key responsibilities include the review of the consolidated financial statements, systems of internal financial and compliance control.

The governance of the Company is the responsibility of the Board of Directors and the Audit, Finance & Risk Committee of the Board, who are also responsible under law for the supervision of the management of the Company's businesses and affairs and have the statutory authority and obligation to act honestly and in good faith with a view to the best interests of the Company.

The Board makes independent decisions and also receives recommendations from the following committees of the Enbridge Inc. Board of Directors, who act in an advisory capacity to the Board of Directors of the Company:

- Governance Committee
- Human Resources & Compensation Committee
- Corporate Social Responsibility Committee

In addition to the committee structure and mandate of the Board of Directors outlined above, the Board of Directors has adopted and governs itself in accordance with Enbridge Inc.'s corporate governance practices as expressed in the *Corporate Governance Practices* of Enbridge annually disclosed in its *Management Information Circular* (last dated March 2, 2011), which is incorporated herein by reference.

BOARD STAFF INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/Tab3/Sch 2/Appendix A Mercer Report, Updated Estimated 2013-2017 Accrual Costs – EGD Pension Plans – 01 June 2012

Ex. A2/Tab3/Sch 2/Appendix B Mercer Report, Updated Estimated 2013-2017 Cash Funding Costs – EGD Pension Plans – 01 June 2012

EGD updated its assumption of the discount rates for defined benefits pension costs to 4.33% for the accrual basis of recording pension costs.

As per page 12 of Appendix A, Mercer stated:

> The discount rate assumption has been updated from the rate used in the December 31, 2011 valuation to reflect market conditions as at March 31, 2012 and the CIA discount rate methodology proposed in September 2011.

As per page 19 of Appendix B, Mercer stated that the discount used for the cash basis of recording pension costs is 5.75%.

a) Please provide the yield curve to show that the discounted rates used is supported by the yield curve of long term bonds. Please describe the yield curve used. Please explain.

b) Please provide the discount rate used in the December 31, 2011 valuation and the supporting documentation.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

c) Please also demonstrate that the long term bonds selected by EGD covering a time period horizon approximate the period of EGD's future benefit payments for its defined benefit pension plans.

d) Please explain why the discount rate used for the valuation on the accrual basis is 4.33% in Appendix A and on the cash basis is 5.75% in Appendix B as at December 31, 2011.

   i. Please explain why two different rates are used as at December 31, 2011. Please reconcile the differences.
   ii. Please explain the implications of these two different discount rates on the 2013 Test Year pension expense calculated on an accrual basis and the 2013 Test Year pension expense calculated on a cash basis.

e) Expected rate of return on invested assets for EGD – RPP is 7% as per page 17 of Appendix A on an accrual basis and 6.64% as per page 21 of Appendix B on a cash basis.

   i. Please explain why two different rates are used as at December 31, 2011. Please reconcile the differences.
   ii. Please explain the implications of these two different discount rates on the 2013 Test Year pension expense calculated on an accrual basis and the 2013 Test Year pension expense calculated on a cash basis.
   iii. Please explain further how the expected returns on plan assets are determined.
   iv. Please provide EGD's internal analysis of these two figures.

RESPONSE

a) For determining pension costs on an accrual basis Enbridge (supported by Enbridge's external auditors) adopted the discount rate methodology proposed by the Canadian Institute of Actuaries in September 2011 (the "CIA methodology"). As such the appropriate yield curve is specified in the CIA methodology. Attached is a copy of the CIA's Educational Note (Attachment I) which contains details on how the yield curve is derived and justification for this methodology.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

The yield curve used to determine the discount rate of 4.5% as of December 31, 2011 and 4.33% as of March 31, 2012 is provided in Attachment 2 and 3. Note that underlying bonds used to determine the yield curve were not selected by Enbridge but were prepared by Fiera Capital, an independent investment management firm the CIA has retained to prepare the yield curve in accordance with the CIA methodology for determining discount rates. This data can be found for any month-end directly on Fiera Capital's website (http://www2.fieracapital.com/en-ca/fiera-capitals-cia-method-accounting-discount-rate-curve/cia-curve.html)

Representative cash flows for the pension plan are projected and discounted at the spot rates shown in the attachments, and a single equivalent discount rate is then calculated.

For determining pension costs on a cash basis, the discount rate of 5.75% is based on expectations for the plan's investment returns over the long term (with specified adjustments) and not a yield curve.

b) A discount rate of 4.5% was used in the December 31, 2011 accrual basis valuation. Please see Attachment 4, page 14. A cash basis valuation report as of December 31, 2011 was not prepared by Mercer as it does not need to be filed this year.

c) As mentioned the underlying bonds used to determine the yield curve as attached were not selected by Enbridge but were prepared by Fiera Capital in accordance with the CIA methodology for determining discount rates.

The projected future benefit payments for Enbridge's pension plan extend out beyond 80 years, while the bonds used to determine the yield curve and calculate the discount rate have terms to maturity of less than 30 years. As such the portion of the yield curve beyond 30 years is set equal to the 30 year spot rate which is in accordance with accepted actuarial practice in Canada.

This question is not applicable for the cash basis for determining pension costs as a yield curve is not used.

d) The objectives for calculations on the accrual basis (used for financial reporting) and calculations on the cash basis (used to determine cash funding requirements) are completely separate and unique. As a result, the prescribed methods and requirements used by Mercer to set discount rates on these two bases are not related.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

In general, discount rates for the accrual basis are determined to be in accordance with the applicable accounting standards (US GAAP in this case), while discount rates for the cash basis are determined in accordance with actuarial standards of practice and applicable pension legislation.

The discount rate for the accrual basis valuation of 4.33% is the market-based discount rate as of March 31, 2012 (assumed to remain constant throughout the projection period).

The discount rate for the cash basis valuation of 5.75% is the best estimate of the long term investment return on the plan fund (with specified adjustments) as of March 31, 2011 (assumed to remain constant throughout the projection period).

A reconciliation between the two rates, or the impact on the 2013 Test Year pension expense would not be meaningful or appropriate.

e) There are two variables in question: Enbridge's Expected Return on Assets ("EROA") assumption (used for the accrual basis only) and the long-term assumed investment return used to project forward the plan's assets and cash flows (used for both the accrual basis and the cash basis).

Enbridge's EROA is set by company management and is used to calculate the P&L component of the pension charge under US GAAP. This rate was 6.98% as of December 31, 2011 (assumed to remain constant throughout the projection period).

Mercer's projections then incorporate an assumption as to the long-term return on the plan's assets and cash flows. This rate was 6.37% as of March 31, 2012, based on the following:

- Gross return on the plan's assets, based on the current investment mix: 6.64%
  PLUS
- Additional returns from active management: 0.23%
  LESS
- Assumed investment management and administrative expenses: 0.50%
  EQUALS

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

• Long-term net return on plans assets: 6.37%

The table below shows the components of both rates:

Asset Class	Target Asset Mix	Enbridge Assumption	Mercer Assumption
Corporate universe bonds	15.0%	4.7%	3.5%
Government universe bonds	15.0%	3.9%	2.3%
Real return bonds	10.0%	3.0%	2.6%
Canadian equity	21.0%	8.0%	7.4%
Global equity	17.0%	8.0%	7.4%
Emerging market equity	6.5%	10.7%	10.2%
Private infrastructure	9.0%	9.0%	10.5%
Real estate	6.5%	6.0%	6.1%
Sub-total (weighted by target mix)		6.53%	5.95%
Plus: Additional return due to diversification		0.60%	0.69%
Plus: Provision for active equity management		0.45%	0.23%
Plus: Provision for expenses paid from the fund		-0.60%	-0.50%
Equals: Expected net return on assets		**6.98%**	**6.37%**

Enbridge's EROA is used directly in the calculation of the P&L charge on an accrual basis. Any difference between this assumption and actual returns is recognized immediately in Other Comprehensive Income ("OCI") in the current period, and amortized into P&L as an actuarial gain or loss in future periods.

The long-term return assumption is used to project plan assets. Under the cash basis, if plan assets exceed liabilities, no cash contributions are required. If plan assets are below liabilities, Enbridge must contribute the cost of new benefit accruals, and make amortization payments toward the shortfall between assets and liabilities.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

Educational Note

Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans

Task Force on Pension and Post-retirement Benefit Accounting Discount Rates

September 2011

Document 211088

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Memorandum

To: All Pension Actuaries

From: Phil Rivard, Chair
Practice Council

Gavin Benjamin, Chair
Task Force on Pension and Post-retirement Benefit Accounting Discount Rates

Date: September 20, 2011

Subject: **Educational Note – Accounting Discount Rate Assumption for Pension and Post-employment Benefit Plans**

This Educational Note offers advice to pension actuaries who are engaged to provide guidance to a pension plan sponsor on the selection of the discount rate for a Canadian pension plan under Canadian, U.S., or international accounting standards.

This Educational Note has been prepared by the Task Force on Pension and Post-retirement Benefit Accounting Discount Rates ("the Task Force") which was appointed by the Practice Council. Members of the Task Force consist of certain members of the Committee on Pension Plan Financial Reporting (PPFRC), members of the Canadian Institute of Actuaries ("the Institute") who were not members of the PPFRC, and individuals who are not members of the Institute. The Practice Council wishes to express its gratitude to all the Task Force members, who are listed below. (*Not a member of the Institute.)

Wendy Achoy
Gavin Benjamin
Sébastien Cliche
Martin Cyrenne
Douglas Isaac*
Uros Karadzic
Melissa Kirshenbaum
Geoffrey Melbourne
Boris Pavlin*
Marlene Puffer*
Martin Raymond
Guillaume Turcotte
David Walsh*

In accordance with the Institute's Policy on Due Process for the Approval of Guidance Material other than Standards of Practice, this Educational Note has been prepared by the Task Force and has received final approval for distribution by the Practice Council on September 13, 2011.

As outlined in subsection 1220 of the Standards of Practice, "*The actuary should be familiar with relevant Educational Notes and other designated educational material*." That subsection explains further that a "practice which the Educational Notes describe for a situation is not necessarily the only accepted practice for that situation and is not necessarily accepted actuarial practice for a different situation." As well, "Educational Notes are intended to illustrate the application (but not necessarily the only application) of the standards, so there should be no conflict between them."

If you have any questions or comments regarding this Educational Note, please contact Gavin Benjamin at his CIA Online Directory address, gavin.benjamin@towerswatson.com.

On the first issue, it is understood that "high quality" in Canada has generally been interpreted as referring to market yields on corporate bonds rated Aa or higher, as is the practice in most other countries where Accounting Standards also apply. It is worth noting that in the U.S., the Securities Exchange Commission has provided an interpretation under U.S. accounting standards that "high quality" means the two highest credit ratings given by a recognized ratings agency (e.g., a fixed income security that receives a rating of Aa or higher from Moody's Investors Service). An excerpt from that interpretation is provided in appendix A.

It is worth noting that at the time of preparation of this Educational Note, there were no Aaa-rated corporate bonds denominated in Canadian dollars with long maturities. As a practical matter, the rest of this Educational Note references Aa-rated corporate bonds as being representative of "high quality" bonds in Canada. An actuary may consider including Aaa-rated corporate bonds as "high quality" bonds in the analysis if they become available.

The second and third issues are discussed in the sections that follow.

Appendix B to this Educational Note contains a summary of the key elements of the Accounting Standards that are relevant to the selection of the discount rate.

3. INSUFFICIENT HIGH-QUALITY CORPORATE BONDS WITH LONG MATURITIES IN CANADA

Given the long-term nature of pension plan obligations, the yields that matter most for purposes of selecting the discount rate for a pension plan are often the yields for debt instruments with long terms to maturity (e.g., maturities of 15 years and above). While there is a deep market of Aa-rated corporate bonds denominated in Canadian dollars with short and medium terms to maturity, there are few Aa-rated corporate bonds with terms to maturity beyond 15 years. For example, based on one data source which is considered representative of the Canadian market, at March 31, 2011 there were five Aa-rated corporate bonds with maturities beyond 10 years that had a market capitalization of at least $100 million, only one of which had a maturity beyond 20 years.

In light of such scarcity in Aa-rated corporate bonds with long maturities, actuaries would consider the fact that yield curves developed from such a small pool of bonds may require a significant amount of subjectivity and may also lead to a lack of credibility in the outcome which could be heavily influenced by only a handful of issuers of long corporate bonds. Therefore, in preparing this Educational Note, various possibilities for improving the information used in the construction of the yield curve were reviewed.

4. APPROACH FOR SELECTING THE DISCOUNT RATE

When engaged to provide guidance on the selection of the discount rate assumptions, a reasonable approach commonly used by actuaries would consist of,

> developing a yield curve based on Aa-rated corporate bond data or alternatively obtaining such a curve from a third party provider. When developing the curve (or analyzing the curve provided by a third party), it is important that the actuary understand the underlying data, methods and assumptions that were used in constructing the curve, in particular with respect to extrapolating the long end of the yield curve.

converting the yields on the curve described in the immediately preceding step into spot rates (i.e., yields on zero coupon bonds). This is done because the yield at any point on the curve described in the immediately preceding step represents a blend of the yields on the semi-annual coupons and the yield on the principal that is repaid at the time the bond matures. The appropriate yields to reference in order to discount the projected stream of pension benefit payments would be yields on zero coupon bonds. Pension actuaries would be familiar with the difference between yield and spot curves.

calculating the present value of the pension plan's expected benefit payments using the spot rates developed in the immediately preceding step.

the actuary recommending the discount rate assumption that would be the unique discount rate that, when applied to the plan's expected benefit payments, provides for an equivalent present value as calculated in the immediately preceding step.

5. CONSIDERATIONS WHEN DEVELOPING AA-RATED CORPORATE YIELD CURVE

The following are some factors the actuary would consider when assessing the appropriateness of an Aa-rated corporate yield curve developed for accounting discount rate purposes, as described in the first step of section 4 above.

A. The approach used to extrapolate the long end of the yield curve, given the scarcity of Aa-rated corporate bonds with long maturities.

   Due to the long-term nature of pension obligations, the long end is often the portion of the yield curve that matters most for purposes of establishing the discount rate. A detailed discussion on extrapolating the long end of the yield curve is contained in sections 6 and 8 and in appendix C.

B. The characteristics of the bonds that have been included in the universe used to develop the yield curve.

   It may be appropriate to consider excluding bonds with an outstanding market value below a certain threshold (e.g., $100 million) because bonds with smaller market values tend to be traded less frequently than bonds with larger market values and, thus, their pricing may be considered less reliable.

   The actuary would consider excluding any bonds with characteristics that render the bond inappropriate for purposes of matching the timing and amount of expected payments from a pension plan. For example, the actuary would consider excluding bonds with one or more of the following features: callable (unless the call option includes a make-whole provision or the actuary is comfortable that the call option does not have a material effect on the bond price), putable, convertible, sinkable, extendable, perpetual, variable coupon, and inflation linked. At the time of preparation of this Educational Note, there are few corporate bonds denominated in Canadian dollars with characteristics that render them inappropriate for matching the timing and amount of expected benefit payments from a pension plan.

   The actuary would determine whether debt instruments such as private placements have been included in the universe. For a private placement, the

robustness of its pricing would be a key consideration in determining whether to include it or not.

The actuary would consider whether it is appropriate for bonds issued by government agencies or quasi-government entities, such as energy utilities, airport authorities or universities, to be considered corporate bonds. If so, they would be eligible for inclusion in the universe used to develop the yield curve. Alternatively, if they are not considered corporate bonds, they could be included when extrapolating the long end of the yield curve subject to further adjustments to reflect Aa-rated corporate risk.

The actuary would consider whether to include outlier bonds (i.e., bonds with very high or very low relative yields). If the actuary decides to exclude outlier bonds, the actuary would consider the yield thresholds beyond which a bond would be classified as an outlier. A possible rationale for excluding outlier bonds could be that very high or low relative yields may indicate unusual characteristics of the bonds, market concerns about the strength of the bond issuer or the credit rating of these bonds, or may suggest an issue with the reliability of the pricing. On the other hand, a possible rationale for including outlier bonds could be that the classification of a bond as an outlier is subjective and the actuary often does not have sufficient knowledge to second-guess the bond ratings or the yield information provided by the bond data source.

Different ratings agencies may assign different ratings to a particular bond. For example, one ratings agency may rate a bond as Aa while another ratings agency may rate the same bond as A. The actuary would consider which ratings agency/agencies have been relied upon for purposes of selecting the bonds used to develop the yield curve and whether the choice of the ratings agency/agencies could materially affect the resulting discount rate.

C. During periods of financial market volatility, the actuary would consider the following matters with respect to the appropriateness of the bond yield information used to develop the yield curve.

If a bond has not been traded recently, the yield information provided for the bond is often based on the yields of similar bonds that were recently traded. During periods of financial market volatility, this approach for estimating the yield may become less reliable.

During periods of financial market volatility, the spread between the bid and ask yields may increase. The actuary would consider whether to use the bid yields, ask yields, or something in between the two (e.g., the average of the bid and ask yields).

The actuary would consider whether the yield information is dominated by either new issues or secondary sales. Bond issuers will often offer a new issue concession (i.e., higher yield) relative to the yield on the secondary sale of the same bond. While new issue concessions are not normally significant, they can increase significantly and become material during periods of financial market volatility.

The above information may not be readily available from the bond information the actuary normally receives. In that case, the actuary would generally question the data provider to understand how these issues are reflected in the data provided.

D. The actuary would consider the manner in which bond yields are weighted when developing the yield curve.

One approach is to weight each bond by its market capitalization. However, the actuary would consider whether a few bonds with large relative market capitalizations are having undue influence on the resulting discount rate.

A second approach is to weight each bond equally. However, the actuary would consider whether a large number of bonds with small relative market capitalizations are having undue influence on the resulting discount rate.

A third approach is to use weightings which are between the two approaches above.

E. Fitting a yield curve to the available bond yield data requires judgment and the use of methodologies (e.g., a regression technique). The actuary would consider whether appropriate judgment is being applied, especially at the long end of the curve where bond yield information may be scarce.

6. EXTRAPOLATING THE LONG END OF THE YIELD CURVE: APPROACHES CONSIDERED

A number of approaches for extrapolating the long end of the yield curve have been assessed, given the scarcity of corporate bonds rated Aa and above with maturities beyond 10 years. The underlying objective of all the approaches that were examined is to increase the number of relevant data points used to extrapolate the long end of the yield curve, thereby avoiding reliance on too few data points.

The following approaches to extrapolate the long end of the yield curve have been considered and analyzed in detail.

A. For maturities greater than 10 years, supplement the Aa-rated corporate bonds with A-rated corporate bonds with or without a spread adjustment to reflect the additional credit risk of A-rated bonds (both approaches were analyzed).

B. For maturities greater than 10 years, supplement the Aa-rated corporate bonds denominated in Canadian dollars with Aa-rated corporate bonds denominated in U.S. dollars that are further translated into Canadian dollars.

C. For maturities greater than 10 years, use Canadian provincial bonds rated Aa to which a spread adjustment is added to reflect the additional credit risk of Aa-rated corporate bonds.

Further details and commentary regarding each of the above approaches are provided below.

A. For maturities greater than 10 years, supplement the Aa-rated corporate bonds with A-rated corporate bonds, with or without a spread adjustment to reflect the additional credit risk of A-rated bonds.

In order to increase the number of data points used to extrapolate the long end of the yield curve, the Aa-rated corporate bonds used to develop the long end of the yield curve are supplemented with A-rated corporate bonds.

The addition of A-rated corporate bonds adds a significant number of data points at longer maturities. For example, at March 31, 2011, based on one data source which is considered representative of the Canadian market, there were 105 A-rated corporate bonds with maturities beyond 10 years that had a market capitalization of at least $100 million, 67 of which had maturities beyond 20 years.

A-rated bonds are generally considered upper-medium grade (compared to high grade for Aa-rated bonds) and the issuers of such bonds are generally seen as having a strong capacity to meet their financial commitments (compared to a very strong capacity for Aa-rated bond issuers) and the market would generally assign wider credit spreads for A-rated versus Aa-rated bonds of similar duration/maturity in the same sector. Therefore, a spread adjustment may be subtracted from the yields on A-rated corporate bonds when extrapolating the long end of the yield curve.

B. For maturities greater than 10 years, supplement the Aa-rated corporate bonds denominated in Canadian dollars with Aa-rated corporate bonds denominated in U.S. dollars that are further translated into Canadian dollars.

   This approach is based on the premise that Canadian pension plans have access to deep international high-quality corporate bond markets, whose cash flows could be used to match the timing and amount of expected benefit payments from a Canadian pension plan. Under this approach, Aa-rated corporate bonds denominated in Canadian dollars are supplemented with Aa-rated corporate bonds denominated in U.S. dollars with maturities greater than 10 years in order to increase the number of data points used to establish the long end of the yield curve.

   This approach adds a significant number of data points at longer maturities. For example, at March 31, 2011, based on one data source which is considered representative of the U.S. market, there were 117 Aa-rated corporate bonds denominated in U.S. dollars with maturities beyond 10 years that had a market capitalization of at least $100 million, 81 of which had maturities beyond 20 years.

   For the U.S. bonds, the U.S. dollar yields would be translated into Canadian dollar yields using market data on swap rates.

   This approach is included in the initial analysis of the different approaches that is summarized in appendix C. Although this approach appears to be attractive because of the deepness of the U.S. bond market, it is understood that it may not be considered permissible under current Accounting Standards due to the underlying data being denominated in a currency other than Canadian dollars. Therefore, Approach B was not retained as a viable option by the Task Force.

C. For maturities greater than 10 years, use Canadian provincial bonds rated Aa to which a spread adjustment is added to reflect the additional credit risk of Aa-rated corporate bonds.

   This approach takes advantage of the fact that the market for high-quality Canadian provincial bonds is deep across the entire yield curve. For example, at March 31, 2011, based on one data source which is considered representative of the Canadian market, there were 71 Aa-rated provincial bonds with maturities beyond 10 years that had a market capitalization of at least $100 million, 42 of which had maturities beyond 20 years.

   For purposes of developing the yield curve, Aa-rated corporate bonds are used for maturities up to 10 years since the market is sufficiently deep at these maturities. For maturities greater than 10 years, the yield curve is extrapolated using Aa-rated Canadian provincial bonds. In order to reflect the difference in credit risk between Aa-rated corporate bonds and Aa-rated provincial bonds, a spread adjustment is added to the provincial bond yields.

7. FEEDBACK ON EXTRAPOLATION APPROACHES

In order to increase the likelihood that this guidance will be acceptable to auditors, feedback was requested from the Canadian audit firms' Technical Partners Committee (TPC) on Approaches A and C for extrapolating the yield curves that are described in section 6. While guidance from the TPC is not binding on Canadian auditors, it is understood that TPC guidance provides a strong indication of the approaches and methods that will likely be acceptable to Canadian auditors.

After considering the information provided, the TPC indicated that they have a preference for Approach C, since they view the methodology for extrapolating the Aa-rated corporate yield curve beyond 10 years to be reasonable. Also, in their view, this approach is most consistent with Canadian accounting standards as it is somewhat consistent with question and answer 41R of the CICA's *Employee Future Benefits Implementation Guide*. (Question and answer 41R is reproduced in appendix B.) In addition, Approach C is not based on bonds rated below Aa, which is a characteristic of Approach A.

Based on the Task Force's analysis and the guidance provided by the TPC, it was concluded that Approach C is an appropriate approach for extrapolating the yield curve in accordance with current Accounting Standards.

8. DERIVING THE SPREAD ADJUSTMENT TO ACCOUNT FOR THE CREDIT RISK OF AA-RATED CORPORATE BONDS

In order to implement Approach C, a methodology is needed for deriving an appropriate spread adjustment to the Aa-rated Canadian provincial bond yields to account for the additional credit risk of Aa-rated corporate bonds.

Deriving an appropriate spread adjustment under Approach C to translate Canadian provincial Aa bond yields into Canadian corporate Aa bond yields for bonds with maturities in excess of 10 years requires judgment. It is recognized that there are different ways to calculate such spread, but herein is suggested a methodology that is believed to be reasonable while not overly complex.

The suggested methodology can be described as follows:

A base spread, denominated $Spread^{base}$, would be calculated first. This base spread would be measured in a portion of the universe where there are sufficient data to derive a credible spread. For example, it may be reasonable to use the average spread between Aa-rated corporate and Aa-rated provincial bond yields with terms between five and 10 years.

It is recognized that there may be an additional spread between Aa-rated corporate bonds and Aa-rated provincial bonds at longer maturities, but such additional spread is difficult to measure (due to lack of data) and is thought to be usually relatively small. A study was done over the period from June 2004 to December 2009, which compared the spread between Aa-rated corporate bonds and Aa-rated provincial bonds at different maturities. The provincial bonds were comprised of an equal blend of issues from Québec and Ontario. Based on the study, the additional spread at terms from 21 to 30 years relative to the spread at terms from six to 10 years was, on average, 0.11% over the period, but ranged from 0% to 0.57% with the following exception. At December 31, 2008, which was at the height of the financial crisis, the additional spread was negative (-0.63%).

It is believed that most of the increase in spreads in corporate Aa yields above "risk-free" yields (i.e., above yields on securities issued by the Government of Canada) expected as the maturity of a bond increases is typically already reflected in the pricing of Aa-rated provincial bonds. Initially, it was suggested that, typically, no such additional spread need be assumed. However, following comments from various parties arguing for the use of as much as possible of the available data at long maturities, even if the data are scarce, it was concluded that it would be appropriate to suggest making an allowance for the additional spread at maturities beyond 10 years. One possible methodology for making this additional allowance would be to reflect one-half of the average spread calculated over the period from 11 to 30 years that is in excess of the average base spread calculated between five and 10 years. This methodology is described more precisely in the remainder of this section.

If the average spread calculated between 11 and 30 years is defined as $Spread^{long}$ and the excess spread as $Spread^{excess}$ then,

$Spread^{long}$ is calculated as the average spread between Aa-rated corporate and Aa-rated provincial bond yields with terms between 11 and 30 years using available data, even if scarce, and

$Spread^{excess}$ is calculated as 50% x ($Spread^{long} - Spread^{base}$).

Based on this methodology, the total spread to be added to the yields of Aa-rated provincial bonds with maturities in excess of 10 years would be calculated as

$$Spread^{Prov10+} = Spread^{base} + Spread^{excess}$$

which is equivalent to

$$Spread^{Prov10+} = Spread^{base} + 50\% \text{ x } (Spread^{long} - Spread^{base})$$

which is equivalent to

$$Spread^{Prov10+} = 50\% \text{ x } Spread^{base} + 50\% \text{ x } Spread^{long}$$

It is recognized that the suggested methodology includes a number of simplifications and a judgmental estimate of the credibility factor of 50% applied to the additional spread measured at maturities over 10 years. However, the suggested methodology has the advantage of being relatively easy to implement. Also, the credibility factor of 50% represents a reasonable compromise between no allowance at all for an additional spread beyond 10 years, which would imply that available corporate Aa-rated data beyond 10 years are not reflected, and a credibility factor of 100%, which would ignore the reality, as described in section 3, that in Canada there are few high-quality corporate bonds with long maturities. The actuary would use judgment in applying this methodology.

9. ILLUSTRATION OF THE YIELD CURVE DEVELOPED AS PER APPROACH C

The objective of this section is to illustrate the development of a yield curve based on Approach C described in section 6 above and the calculation of the spread described in section 8 above. The illustration describes one possible approach to develop the yield curve but it is recognized that other approaches may exist. The key steps in developing the yield curve are described below.

1. Select a suitable set of Aa-rated corporate and provincial bonds after consideration of the factors described in section 5.
2. Calculate the spread adjustments described in section 8 as follows.
   a) Calculate the difference/spread in bond yields between the corporate and provincial bonds of similar maturities for all bonds with a maturity between five and 10 years and for all bonds with a maturity above 10 years. This calculation could be simplified by grouping bonds that fall within a maturity band. For example, all bonds with a maturity between 7.50 and 8.49 years would be grouped and referenced as bonds with an eight-year maturity;
   b) Calculate $Spread^{base}$ as the average of the spreads calculated in 2.a) for bonds of maturities between five and 10 years. If using the simplified grouping approach mentioned in 2.a), this average could be derived by averaging the spreads calculated at maturities of five, six, seven, eight, nine, and 10 years;
   c) Calculate $Spread^{long}$ as the average of the spreads calculated in 2.a) for bonds of maturities between 11 and 30 years. Due to the small number of corporate bonds with maturities beyond 11 years, these bonds are not grouped into smaller maturity bands;
   d) Calculate $Spread^{excess}$ as 50% x ($Spread^{long} – Spread^{base}$).
   e) $Spread^{Prov10+} = Spread^{base} + Spread^{excess}$.
3. Add $Spread^{Prov10+}$ to the yield of each Aa-rated provincial bond with a maturity greater than 10 years.
4. Finally, fit a curve to the Aa-rated corporate bonds of maturities up to 10 years and the provincial bonds of maturities greater than 10 years adjusted with the spread calculated as described above. The resulting yield curve would be the starting point to derive accounting discount rates following the steps described in the last three steps of section 4.

This yield curve could be developed using a smoothing or regression technique that aims at fitting a yield curve to the selected bond yield data at the measurement date.

10. PUBLISHING A MONTHLY CURVE

The Task Force has recommended that the Canadian Institute of Actuaries consider partnering with a third party to produce a monthly spot curve derived from a yield curve based on Approach C that will be accessible to pension actuaries. Engaging a third party to produce monthly spot curves creates efficiencies by avoiding the need for actuarial firms and other parties to each set up their systems to implement Approach C. It would also lend itself to a consistent application of the suggested methodology.

This recommendation is not intended to imply that the Task Force believes that Approach C represents the only appropriate methodology for developing a high-quality corporate spot curve to be used in developing discount rates for accounting purposes. While other appropriate methods likely exist, the intention is to provide pension practitioners, plan sponsors, auditors and others with ready access to a monthly spot curve that the Task Force believes is appropriate given the research that it has conducted.

11. STANDARDS OF PRACTICE AND USING THE WORK OF OTHERS

Whether an actuary is relying on a yield curve purchased from a third party or pricing and ratings data for individual bonds, the actuary is using the work of another person. If the actuary's work is destined for use in Canada, the actuary's work is subject to Canadian actuarial standards of practice. When subject to Canadian actuarial standards of practice, the actuary would consider the following paragraphs of the Standards of Practice, which are reminders of the responsibility of an actuary to assess whether work obtained from others is appropriate to use for purposes of the actuary's work.

> Paragraph 1610.03: "Use of the work of outsiders raises questions. Is their work appropriate? Should the actuary take responsibility for it?"
>
> Paragraph 1610.05: "If the actuary does not take such responsibility, then the actuary reports with reservation . . ."
>
> Paragraph 1610.06: "Even when the actuary is not taking responsibility for the data, however, he or she would not accept supplied data blindly, but would make checks of reasonableness, if only to assure that the data had lost nothing in the transmission and that the actuary's understanding of the data is the same as the supplier's."

When assessing whether the yield curve purchased from a third party or the pricing and ratings data for individual bonds provided to the actuary is appropriate, the actuary would consider the guidance contained in this Educational Note. The actuary would pay particular attention to the manner in which the scarcity of Aa-rated corporate bonds with long maturities was addressed when developing the yield curve or in the data provided.

12. CONCLUSION

The various issues mentioned in the preceding sections of this Educational Note were examined and different approaches were explored for developing a high-quality corporate bond yield curve from which discount rates could be derived to value pension obligations. Subsequently the possible options were narrowed down, feedback was sought from the TPC and it was concluded that Approach C represents an appropriate approach in most economic environments, including the current environment. Further

information about the associated work was provided in a webcast held on November 25, 2009 and in a session at the CIA Pension Seminar in Montréal on November 3, 2010.

Throughout its work, the objective of the Task Force was to address the scarcity of Aa-rated corporate bonds with long maturities in the Canadian market. Approach C uses Aa-rated provincial bonds at maturities beyond 10 years. The Aa-rated provincial bond market is liquid and deep across all terms to maturity and provides a solid base from which to extrapolate the corporate Aa-rated yield curve beyond 10 years. In order to adjust the yields on the provincial Aa-rated bonds to reflect the risk characteristics of high-quality corporate bonds, the use of as much information from current long-term high-quality corporate bonds as possible was reviewed. Although some judgment is required in developing this spread adjustment, it was concluded that the identified approach will provide for a reasonable yield curve to be used in providing guidance to plan sponsors on the selection of accounting discount rates.

If the number of long-term Aa-rated corporate bonds increases in the future (e.g., due to the issuance of more of these bonds or due to the upgrade of A-rated bonds to Aa rating), the actuary would use his or her judgment in deciding whether the changed environment enables reference to Aa-rated corporate bonds alone for purposes of developing a high-quality corporate yield curve.

Similarly, if a significant number of Aa-rated provincial bonds were to lose their Aa ratings, the actuary would evaluate the continued appropriateness of Approach C.

Pension actuaries are encouraged to consider the guidance described in this Educational Note, while recognizing that approaches other than Approach C could be acceptable with sufficient justification by the actuary. Pension actuaries are also reminded that decisions with respect to methods and assumptions used to prepare financial statements are made by the plan sponsor and not the actuary (although actuaries would be mindful of the potential application of Rule 6 of the Rules of Professional Conduct, Control of Work Product).

APPENDIX A

EXCERPT FROM AN INTERPRETATION OF THE SECURITIES AND EXCHANGE COMMISSION IN THE UNITED STATES ON THE DEFINITION OF HIGH-QUALITY BONDS

In the U.S., a quote from the September 23, 1993 U.S. FASB Emerging Issues Task Force meeting minutes on Administrative and Technical Matters is as follows: "The staff suggests that fixed-income debt securities that receive one of the two highest ratings given by a recognized ratings agency be considered high quality (for example, a fixed-income security that receives a rating of AA or higher from Moody's Investors Service, Inc.)."[3]

[3] Source: Question and answer 41R of the CICA's *Employee Future Benefits Implementation Guide.*

APPENDIX B

ACCOUNTING STANDARDS

This appendix contains a summary of certain Canadian, U.S. and International accounting standards and guidance that are relevant to the determination of the discount rate.

Canadian Accounting Standards

Part II—CICA 3461[4]

Discount rate

.063 *The discount rate used to determine the accrued benefit obligation shall be an interest rate determined by reference to:*

(a) market interest rates at the measurement date on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments; or

(b) the interest rate inherent in the amount at which the accrued benefit obligation could be settled.

.064 The objective of selecting a discount rate is to measure the single amount that, if invested at the measurement date in a portfolio of high-quality debt instruments, would provide the necessary pre-tax cash flows to pay the accrued benefits when due. For example, the current market value of a portfolio of high-quality zero coupon bonds acquired to pay the cost of benefits, when due, equals the amount of the actuarial present value of the benefits because cash inflows equal cash outflows in timing and amount. There is no reinvestment risk in the yields to maturity of the portfolio. However, in other than a zero coupon portfolio, such as a portfolio of long-term debt instruments that pay interest semi-annually or have maturities that do not extend far enough into the future to meet expected benefit payments, the discount rate (the yield to maturity) needs to incorporate reinvestment rates expected to be available in the future. Those reinvestment rates are extrapolated from the existing yield curve at the measurement date.

.065 When rates on high-quality corporate bonds are available, they are used to determine the discount rate. When the maturities of corporate bonds do not extend far enough into the future to match the cash flows inherent in the accrued benefit obligation, the rates on government bonds are used to determine the discount rate for the expected benefit payments that are farther into the future than the corporate bond maturities.

.066 The discount rate reflects the estimated timing of benefit payments. When some benefits are payable after the maturity of all available corporate or government bonds, the present value of that portion of the benefits is unlikely to vary significantly as a result of the selected discount rate. For that portion of the

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benefits, an entity may use a discount rate based on the yield of the last maturing corporate or government bond available.

.067 The discount rate is re-evaluated at each measurement date. When long-term interest rates rise or decline, the discount rate changes in a similar manner.

.068 Immediate settlement of an accrued benefit obligation may be possible through, for example, the purchase of an **insurance contract**, such as an annuity contract, that transfers the significant risks associated with the accrued benefit obligation to a third-party insurer. In such circumstances, the interest rate inherent in the amount at which the accrued benefit obligation could be settled may be used in determining the discount rate.

Employee Future Benefits Implementation Guide—Questions and Answers[5]

Question 41R: What constitutes a "high-quality debt instrument" in terms of the discount rate used to determine the accrued benefit obligation?

*Answer 41R***:** In the U.S., a quote from the September 23, 1993 U.S. FASB Emerging Issues Task Force meeting minutes on Administrative and Technical Matters is as follows: "The staff suggests that fixed-income debt securities that receive one of the two highest ratings given by a recognized ratings agency be considered high quality (for example, a fixed-income security that receives a rating of AA or higher from Moody's Investors Service, Inc.)."

In Canada, ratings on corporate bonds of AA or higher are not as common and there is no specific guidance on what a high-quality debt instrument is. Professional judgment is required in determining the appropriate discount rate. One possibility is to start with the yield on government of Canada bonds, and to add an appropriate adjustment to reflect the risk characteristics of high-quality corporate bonds.

Question 45: If an entity changes its basis of estimating assumed discount rates, for example, by using high-quality bond rates for one year and annuity rates for the following year, is that a change in method of applying an accounting principle?

*Answer 45***:** No. The purpose of paragraphs 3461.050 – .051 *[comments from the editor: these have now been renamed paragraphs 3461.063 - .064 under Part II CICA 3461]* is to describe the objective of selecting assumed discount rates, namely, to determine the interest rates inherent in the price at which the pension benefits could be effectively settled — currently. If an entity that previously used AA bond rates believes that in a subsequent year, in consideration of its pension plan's particular facts and circumstances, the interest rates that would be inherent in an effective settlement of the pension benefits are now more closely reflected by the rates implicit in current prices of annuity contracts, then those rates should be used. The change is viewed as a change in estimate (the estimate is the determination of the effective settlement rates). The key point is that the entity is using the rates implicit in current prices of annuity contracts as the basis to

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determine the best estimate of the effective settlement rates. The decision to use a particular methodology in a particular year does not mean that the entity must use that methodology in subsequent years. A change in the facts and circumstances may warrant the use of a different source that better reflects the rates at which the obligation could be effectively settled — currently. A position that holds such a change as a change in accounting principle would lend credence to the view that there are two or more acceptable alternatives. That is not the case. The objective is to select the best estimate of the effective settlement rates.

Another aspect of this issue is to determine when to change the basis of estimation from one particular methodology (for example, AA bond rates) to another (for example, rates implicit in current prices of annuity contracts). There is no prescribed mathematical formula for making that decision. As indicated above, the emphasis in selecting assumed discount rates should be the use of the best estimate. Changes in the methodology used to determine that best estimate should be made when facts or circumstances change (for example, a general decline or rise in interest rates that has not, as yet, been reflected in the rates implicit in the current prices of annuity contracts). If the facts and circumstances do not change from year to year, it would be inappropriate to change the basis of selection, particularly if the intent in changing the basis is to avoid a change in the assumed discount rate.

U.S. Accounting Standards

Codification 715.30.35-43 and -44[6]

43. Assumed discount rates shall reflect the rates at which the pension benefits could be effectively settled. It is appropriate in estimating those rates to look to available information about rates implicit in current prices of annuity contracts that could be used to effect settlement of the obligation (including information about available annuity rates published by the Pension Benefit Guaranty Corporation). In making those estimates, employers may also look to rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. Assumed discount rates are used in measurements of the projected, accumulated, and vested benefit obligations and the service and interest cost components of net periodic pension cost.

44. The preceding paragraph permits an employer to look to rates of return on high-quality fixed-income investments in determining assumed discount rates. The objective of selecting assumed discount rates using that method is to measure the single amount that, if invested at the measurement date in a portfolio of high-quality debt instruments, would provide the necessary future cash flows to pay the pension benefits when due. Notionally, that single amount, the projected benefit obligation, would equal the current market value of a portfolio of high-quality zero coupon bonds whose maturity dates and amounts would be the same as the timing and amount of the expected future benefit payments. Because cash inflows would equal cash outflows in timing and amount, there would be no reinvestment risk in the yields to maturity of

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the portfolio. However, in other than a zero coupon portfolio, such as a portfolio of long-term debt instruments that pay semiannual interest payments or whose maturities do not extend far enough into the future to meet expected benefit payments, the assumed discount rates (the yield to maturity) need to incorporate expected reinvestment rates available in the future. Those rates shall be extrapolated from the existing yield curve at the measurement date. The determination of the assumed discount rate is separate from the determination of the expected rate of return on plan assets whenever the actual portfolio differs from the hypothetical portfolio described in this paragraph. Assumed discount rates shall be reevaluated at each measurement date. If the general level of interest rates rises or declines, the assumed discount rates shall change in a similar manner.

International Accounting Standards

IAS 19 (last revised in 2008)[7]

78 The rate used to discount post-employment benefit obligations (both funded and unfunded) shall be determined by reference to market yields at the end of the reporting period on high quality corporate bonds. In countries where there is no deep market in such bonds, the market yields (at the end of the reporting period) on government bonds shall be used. The currency and term of the corporate bonds or government bonds shall be consistent with the currency and estimated term of the post-employment benefit obligations.

79 One actuarial assumption which has a material effect is the discount rate. The discount rate reflects the time value of money but not the actuarial or investment risk. Furthermore, the discount rate does not reflect the entity-specific credit risk borne by the entity's creditors, nor does it reflect the risk that future experience may differ from actuarial assumptions.

80 The discount rate reflects the estimated timing of benefit payments. In practice, an entity often achieves this by applying a single weighted average discount rate that reflects the estimated timing and amount of benefit payments and the currency in which the benefits are to be paid.

81 In some cases, there may be no deep market in bonds with a sufficiently long maturity to match the estimated maturity of all the benefit payments. In such cases, an entity uses current market rates of the appropriate term to discount shorter term payments, and estimates the discount rate for longer maturities by extrapolating current market rates along the yield curve. The total present value of a defined benefit obligation is unlikely to be particularly sensitive to the discount rate applied to the portion of benefits that is payable beyond the final maturity of the available corporate or government bonds.

Note that the amended version of IAS 19 published by the International Accounting Standards Board in June 2011 has changed the numbering of the paragraphs above but not the content.

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APPENDIX C

ANALYSIS OF ALTERNATIVES FOR EXTRAPOLATING THE LONG END OF THE YIELD CURVE

The Task Force retained Twist Financial to analyze various approaches for extrapolating the long end of the yield curve. The remainder of this section contains highlights from the analysis. Further details regarding the methodology used and the results of the analysis are contained in the slides prepared for a November 25, 2009 Canadian Institute of Actuaries ("CIA") webcast entitled Pension Accounting Discount Rates.

The following approaches for developing the long end of the yield curve were initially analyzed.

A1. For maturities greater than 10 years, supplement the Aa-rated corporate bonds with A-rated corporate bonds. No adjustment was made to the yields of the A-rated bonds to account for credit spreads between A-rated and Aa-rated bonds.

A2. For maturities greater than 10 years, supplement the Aa-rated corporate bonds with A-rated corporate bonds. In this case, an adjustment was made to the yields of the A-rated bonds to account for credit spreads between A-rated and Aa-rated bonds. The adjustment was determined as the average difference in yields between Aa-rated and A-rated corporate bonds for maturities of six years and less.

B. For maturities greater than 10 years, supplement the Aa-rated corporate bonds denominated in Canadian dollars with Aa-rated corporate bonds denominated in U.S. dollars that are further translated into Canadian dollars.

C. For maturities greater than 10 years, use Canadian provincial bonds rated Aa to which a spread adjustment is added to reflect the additional credit risk of Aa-rated corporate bonds. For purposes of the analysis, the spread adjustment was initially determined as the average difference in yields between Aa-rated corporate bonds and Aa-rated provincial bonds for maturities of six years and less.

D. For illustration purposes and comparison, the Task Force also developed the yield curve using only the available information on Aa-rated corporate bonds.

For each of the five approaches described above, a yield curve and discount rates were developed using available bond yield data after applying the methodology described in section 4. Three illustrative plans were used; a "short-duration" plan, with a modified duration of approximately nine years, a "mid-duration" plan, with a modified duration of approximately 12 years and a "long-duration" plan, with a modified duration of approximately 17 years.

This analysis was conducted using bond yield data at the following three dates:

December 31, 2006, i.e., before the financial crisis of 2008 and early 2009,

December 31, 2008, during the financial crisis, and

October 30, 2009, the most recent month-end prior to the CIA webcast.

The resulting discount rates obtained for the long-duration plan were

Discount Rate for Long-duration Plan			
Approach	**31/12/2006**	**31/12/2008**	**30/10/2009**
A1: supplement with A-rated bonds	5.35%	7.38%	5.88%
A2: supplement with A-rated bonds, adjusted for credit spreads	5.28%	6.54%	5.48%
B: supplement with U.S. Aa-rated bonds, translated into Cdn $	5.20%	6.99%	N/A
C: use Aa-rated provincial bonds, adjusted for credit spreads	4.82%	7.18%	5.51%
D: Aa-rated corporates only	5.01%	7.39%	6.41%

The following are some observations regarding the results of the analysis summarized above.

The discount rates using the different approaches at December 31, 2006 were relatively close, with the exception of Approach C. The difference between the highest and lowest rates was 53 basis points (bps).

The dispersion in discount rates between approaches at December 31, 2008 is much greater than at December 31, 2006. The increase in the dispersion is not surprising, as December 31, 2008 was in the midst of a financial market crisis. The difference between the highest and lowest discount rates at December 31, 2008 was 85 bps.

At October 30, 2009, with the exception of Approach D, the discount rates had converged considerably compared to December 31, 2008. This convergence likely reflected more stability in the fixed income markets relative to December 31, 2008.

One would typically expect that discount rates developed using Approach A (supplement with A-rated bonds) would be higher than discount rates developed using Approach D (Aa-rated bonds alone). However, at October 30, 2009 the discount rate using Approach D was higher by 53 bps. The reason for this apparent anomaly is that, under Approach D, because of the scarcity of Aa-rated corporate bonds of long maturities, the discount rates at December 31, 2008 and October 30, 2009 were heavily influenced by one bond which matures in 2037. This bond is from an issuer in the financial sector and the yields on financial sector bonds increased significantly relative to other industries during the financial crisis, whereas A-rated corporate bonds were better diversified into different industries and were less influenced by the financial crisis.

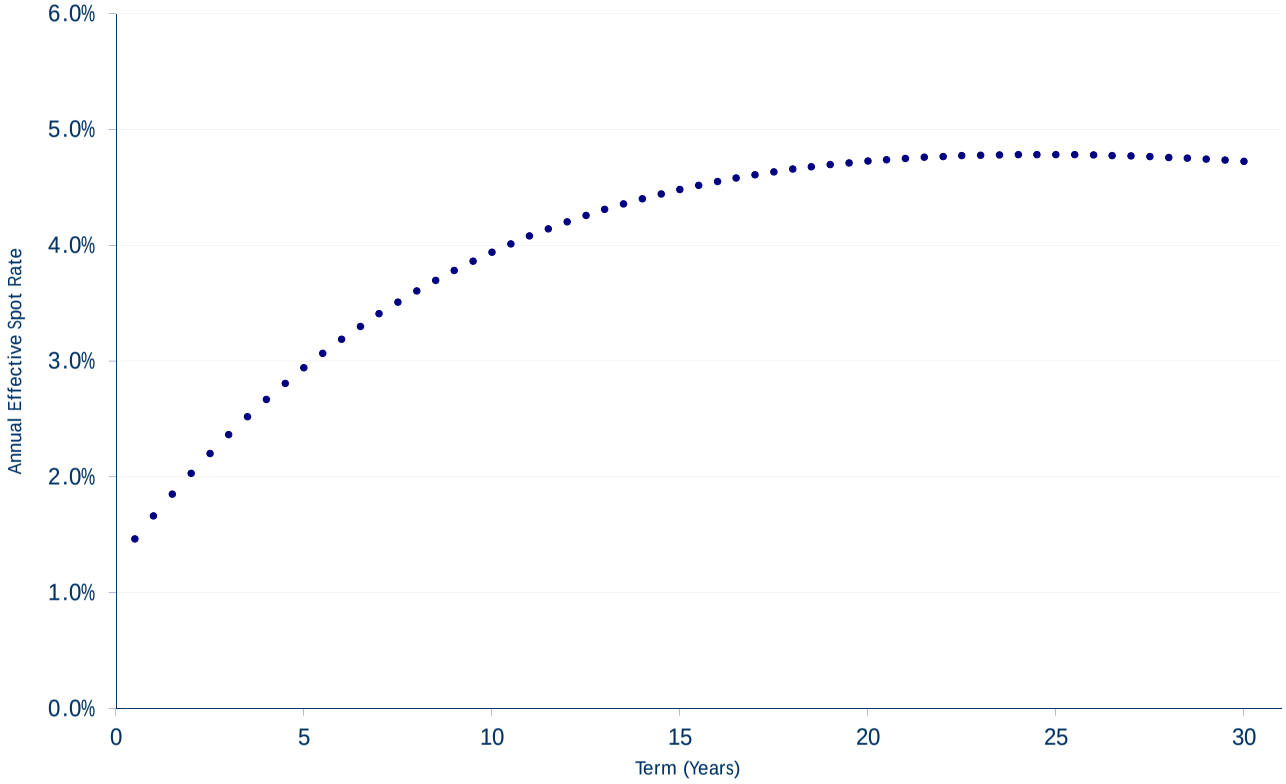
In light of the analysis performed and comments received after the November 2009 webcast, the Task Force deliberated on the alternatives and decided to remove Approach B as a viable approach. It did so because this approach was generally viewed by auditors as not acceptable under current Accounting Standards as it relies on bonds that are not of the same currency as the obligations.

After obtaining guidance from the TPC, it was concluded that Approach C is a reasonable approach for extrapolating the yield curve based on current Accounting Standards. However, it was also concluded that refinement to the method for calculating the spread adjustment to the yields on the Aa-rated provincial bonds would be appropriate. A possible method for calculating the spread is described in section 8.

Production Date : **2011-12-30**

Term (Years)	Annual Effective Spot Rate
0.5	1.4650%
1.0	1.6638%
1.5	1.8513%
2.0	2.0320%
2.5	2.2022%
3.0	2.3660%
3.5	2.5202%
4.0	2.6685%
4.5	2.8078%
5.0	2.9424%
5.5	3.0673%
6.0	3.1884%
6.5	3.3007%
7.0	3.4094%
7.5	3.5100%
8.0	3.6073%
8.5	3.6972%
9.0	3.7843%
9.5	3.8639%
10.0	3.9413%
10.5	4.0118%
11.0	4.0802%
11.5	4.1423%
12.0	4.2025%
12.5	4.2570%
13.0	4.3098%
13.5	4.3570%
14.0	4.4029%
14.5	4.4437%
15.0	4.4831%
15.5	4.5181%
16.0	4.5517%
16.5	4.5812%
17.0	4.6096%
17.5	4.6341%
18.0	4.6576%
18.5	4.6777%
19.0	4.6966%
19.5	4.7127%
20.0	4.7276%
20.5	4.7399%
21.0	4.7511%
21.5	4.7600%
22.0	4.7679%
22.5	4.7738%
23.0	4.7786%
23.5	4.7817%
24.0	4.7837%
24.5	4.7844%
25.0	4.7839%
25.5	4.7823%
26.0	4.7795%
26.5	4.7760%
27.0	4.7711%
27.5	4.7658%
28.0	4.7591%
28.5	4.7521%
29.0	4.7438%
29.5	4.7354%
30.0	4.7256%

Natcan's CIA Method Accounting Discount Rate Curve
December 30, 2011



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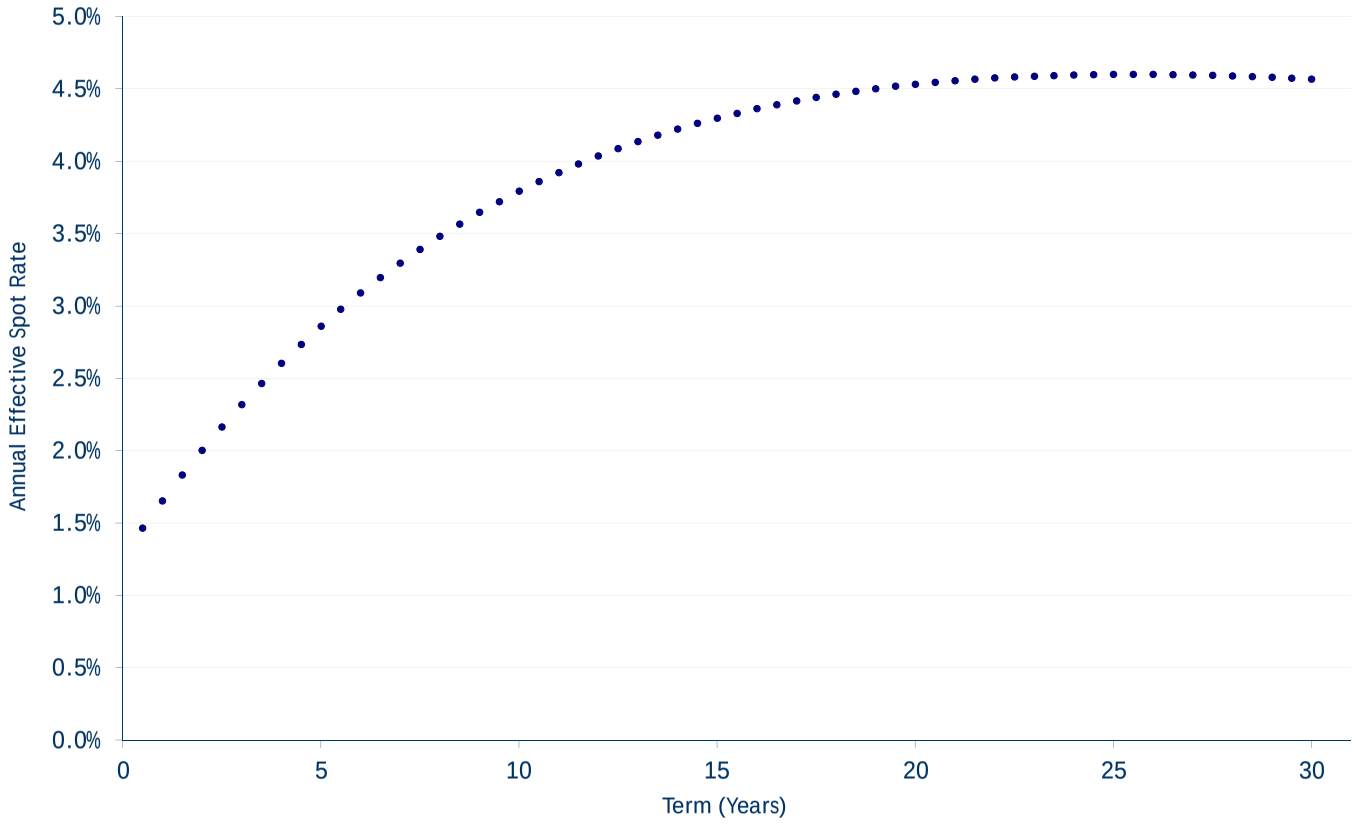
EB-2011-0354
Exhibit I
Issue D4
Schedule 1.8
Attachment 2
Page 1 of 1

NATCAN INVESTMENT MANAGEMENT

Production Date : **2012-03-30**

Term (Years)	Annual Effective Spot Rate
0.5	1.4662%
1.0	1.6539%
1.5	1.8327%
2.0	2.0027%
2.5	2.1645%
3.0	2.3183%
3.5	2.4644%
4.0	2.6039%
4.5	2.7348%
5.0	2.8604%
5.5	2.9782%
6.0	3.0910%
6.5	3.1966%
7.0	3.2977%
7.5	3.3922%
8.0	3.4830%
8.5	3.5668%
9.0	3.6476%
9.5	3.7221%
10.0	3.7938%
10.5	3.8598%
11.0	3.9232%
11.5	3.9814%
12.0	4.0374%
12.5	4.0882%
13.0	4.1372%
13.5	4.1815%
14.0	4.2242%
14.5	4.2626%
15.0	4.2995%
15.5	4.3325%
16.0	4.3642%
16.5	4.3922%
17.0	4.4191%
17.5	4.4426%
18.0	4.4651%
18.5	4.4847%
19.0	4.5031%
19.5	4.5190%
20.0	4.5340%
20.5	4.5465%
21.0	4.5582%
21.5	4.5678%
22.0	4.5764%
22.5	4.5834%
23.0	4.5893%
23.5	4.5938%
24.0	4.5974%
24.5	4.5998%
25.0	4.6012%
25.5	4.6016%
26.0	4.6010%
26.5	4.5997%
27.0	4.5974%
27.5	4.5945%
28.0	4.5906%
28.5	4.5863%
29.0	4.5811%
29.5	4.5756%
30.0	4.5691%

Fiera Capital's CIA Method Accounting Discount Rate Curve as at 2012-03-30



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FIERA CAPITAL

03 February 2012

Enbridge Gas Distribution Inc.

Actuarial Valuation Report
Pension Expense and Employer Disclosure for the Fiscal Year Ending December 31, 2011 Under CICA Section 3461

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Report Highlights

Mercer has prepared this report to assist Enbridge Gas Distribution Inc. and its subsidiary companies (the "Company") and its auditors in preparing financial reports under Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461") relating to the following plans, known collectively as the Enbridge Gas Distribution Inc. Retirement Plans, for the fiscal year ending December 31, 2011:

- The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "RPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP").

The RPP has a defined contribution component as well as a defined benefit component. The results presented in this report consider both components of the RPP. The RPP is funded by contributions from EGD unless it elects to use a funding excess to meet annual contribution requirements. Pension benefits payable from the defined benefit component are based on length of service and final average earnings and are partially indexed for inflation after retirement.

The SERP and the SSERP are closed plans, funded by contributions from EGD as necessary. Pension benefits are based on length of service and final average earnings and are partially indexed for inflation after retirement. There are no longer any active members in the SSERP.

Enbridge Gas Distribution Inc.'s fiscal year end date is December 31, and the measurement date for the plan assets and obligations as described in this report is December 31.

Employer contributions to the pension funds during the fiscal year ending December 31, 2011 were $567,800. These employer contributions were made in

accordance with the following reports effective December 31, 2010 (the "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, effective December 31, 2010;
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates, effective December 31, 2010; and,
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc., effective December 31, 2010.

The next actuarial valuation for funding purposes in respect of the RPP must be as of a date no later than December 31, 2012.

Changes in Plan Provisions

There were no changes in plan provisions since the last disclosure as of December 31, 2010.

Changes in Actuarial Cost Methods

There were no changes in actuarial cost methods since the last disclosure as of December 31, 2010.

However, there was a change in methodology for determining interest on the DB current service cost. Interest on the DB current service cost is now included in the current service cost itself (it was previously included in the interest cost).

This change in methodology only affects the allocation of costs between components, and has no impact on the net periodic pension cost or the accrued benefit obligation at year-end.

Changes in Asset Valuation Method

There were no changes in asset valuation method since the last disclosure as of December 31, 2010.

Changes in Assumptions

There were changes in actuarial assumptions since the last disclosure as of December 31, 2010. Please see the Summary of Assumptions in Appendix A of this report for a description of these changes.

Changes in Accounting Policies

There were no changes in accounting policies since the last disclosure as of December 31, 2010.

Transition to US Accounting Standards

Enbridge will be adopting US accounting standards on January 1, 2012. Due to the requirement to provide comparative information in the first set of financial statements, Enbridge has transitioned to US accounting standards from current Canadian GAAP as of January 1, 2011. On that date, a transition adjustment was made to retained earnings to bring the existing current CICA 3461 balances in line with the requirements of US accounting standards. Enbridge will continue to report under current Canadian GAAP in 2011. Two sets of financial results were maintained for 2011, one for current Canadian GAAP and another one for US accounting standards. In 2012, current Canadian GAAP will cease to exist and US accounting standards will commence with comparative information for 2011.

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Principal Expense and Disclosure Information

A summary of principal pension expense and disclosure information, as required for disclosure purposes pursuant to CICA 3461, from the current fiscal year and the prior fiscal year follows.

Components of Net Periodic Pension Cost	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Current service cost - DB	$16,710,900	$13,675,700
Current service cost - DC	1,345,400	1,717,500
Interest cost	38,937,100	38,390,500
Actual return on DB plan assets	(15,158,900)	(78,793,700)
Actuarial loss (gain) on accrued benefit obligation	125,704,600	80,807,600
Costs arising in the period	**$167,539,100**	**$55,797,600**
Differences between costs arising in the period and costs recognized in the period in respect of:		
▪ Return on plan assets	(37,767,700)	29,215,700
▪ Actuarial loss (gain)	(110,298,200)	(67,993,400)
▪ Past service cost	1,270,600	1,270,600
▪ Transitional obligation (asset)	(25,721,000)	(25,721,000)
Net periodic pension cost recognized	**($4,977,200)**	**($7,430,500)**

Weighted-Average Assumptions for Expense	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Discount rate	5.70%	6.60%
Expected long-term rate of return on plan assets	7.19%	7.18%
Rate of compensation increase	3.50%	3.50%

Weighted-Average Assumptions for Disclosure	December 31, 2011	December 31, 2010
Discount rate	4.50%	5.70%
Rate of compensation increase	3.50%	3.50%

Change in Accrued Benefit Obligation	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Accrued benefit obligation at end of prior year	**$699,580,700**	**$598,176,600[1]**
Current service cost - DB	16,710,900	13,675,700
Interest cost	38,937,100	38,390,500
Employee contributions	0	0
Benefits paid	(32,949,500)	(31,469,700)
Actuarial loss (gain)	125,704,600	80,807,600[2]
Accrued benefit obligation at end of year	**$847,983,800**	**$699,580,700**

Change in Plan Assets	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Fair value of plan assets at end of prior year	**$758,390,900**	**$711,836,200[3]**
Actual return on plan assets	15,158,900	78,793,700[4]
Employer contributions	567,800	948,200
Employee contributions	0	0
Benefits paid	(32,949,500)	(31,469,700)
DC contributions drawn from DB surplus	(1,345,400)	(1,717,500)[5]
Fair value of plan assets at end of year	**$739,822,700**	**$758,390,900**

[1] Based on September 30 measurement date.

[2] Includes a gain from change in measurement date of $22,204,300.

[3] Based on September 30 measurement date.

[4] Includes a gain from change in measurement date of $15,757,100

[5] Includes DC contributions from DB surplus between October 1, 2010 to December 31, 2010 of $319,300.

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Excess (deficit) at end of year	**($108,161,100)**	**$58,810,200**
Unamortized transitional obligation (asset)	(44,783,400)	(70,504,400)
Unamortized past service costs	2,470,600	3,741,200
Unamortized net actuarial loss (gain)	376,467,500	228,401,600
Accrued benefit asset (liability)	**$225,993,600**	**$220,448,600**

Weighted-Average Invested Plan Assets by Category	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Equity securities	49%	52%
Debt securities	45%	41%
Other	6%	7%
Total	**100%**	**100%**

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Certification

Mercer has prepared this report exclusively to assist Enbridge Gas Distribution Inc. and its subsidiary companies and auditors in preparing financial reports under Section 3461 of the Canadian Institute of Chartered Accountants Handbook relating to the Enbridge Gas Distribution Inc. Retirement Plans for the fiscal year ending December 31, 2011.

This valuation report may not be used or relied upon by any other party or for any other purpose. Mercer is not responsible for the consequences of any unauthorized use.

A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, plan expenses and the amount earned on any assets invested to pay the benefits. These amounts and others are uncertain and unknowable at the valuation date, but are predicted to fall within a reasonable range of possibilities.

To prepare this report, *actuarial assumptions*, as described in Appendix A, are used to select a single scenario from the range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in mandated requirements, plan experience, changes in expectations about the future, and other factors. Due to the limited scope of the assignment, we did not perform, and thus do not present, an analysis of the potential range of future possibilities and scenarios.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related

issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

Actuarial Valuations and Extrapolations

We have prepared an actuarial valuation of the Enbridge Gas Distribution Inc. Retirement Plans' accrued benefit obligations for accounting purposes as at December 31, 2009 and extrapolated those results to December 31, 2010. The extrapolation of the accrued benefit obligations is based on assumptions as at December 31, 2010 and on actual cash flows for fiscal 2010. In accordance with our mandate, the purpose of this valuation and extrapolation is to account for the costs of the plan for the fiscal year beginning January 1, 2011 and ending December 31, 2011 in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461").

In addition, we have prepared a second actuarial valuation of the Enbridge Gas Distribution Inc. Retirement Plans' accrued benefit obligations for accounting purposes as at December 31, 2010 and extrapolated those results to December 31, 2011. The extrapolation of the accrued benefit obligations is based on assumptions as at December 31, 2011 and on actual cash flows for fiscal 2011. In accordance with our mandate, the purpose of this valuation and extrapolation is to enable Enbridge to satisfy year-end disclosure requirements under CICA 3461.

The financial positions of the plan and the determination of net periodic pension cost set out in this report are based on unaudited financial statements as of December 31, 2010 and December 31, 2011.

Plan Provisions

The results of the valuations set forth in this report reflect the contractual provisions of the plans as of the dates of the valuations and extrapolations as reported to us by Management.

The plans have not been amended since the last valuation and extrapolation for accounting purposes as at December 31, 2010. A summary of the plan provisions is provided in Appendix F of the following reports (the "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, effective December 31, 2010;
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates, effective December 31, 2010; and,
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc., effective December 31, 2010.

Substantive Commitment

There was no substantive commitment as defined under CICA 3461 reported to us by Management.

Data

The valuations are based on the plan asset data presented in the unaudited trust statements prepared by CIBC Mellon for the period from January 1, 2010/ January 1, 2011 to December 31, 2010/December 31, 2011. The pension fund is held in trust by CIBC Mellon and is invested in accordance with the investment policy of Enbridge Gas Distribution Inc. Plan assets of the SERP and SSERP also include the refundable tax account held by the Canada Revenue Agency (the "CRA").

The plan asset data are summarized in the Principal Expense and Disclosure Information section of this report. We have tested the pensions paid and the lump-sum refunds for consistency with the membership data for the plan members who have received benefits. The results of these tests were satisfactory.

The valuations are also based on the membership data as at December 31, 2010 provided by Enbridge Gas Distribution Inc. The membership data, and the validation checks made on the data, are summarized in Appendix E of the Funding Reports.

Subsequent Events

After checking with representatives of Enbridge Gas Distribution Inc., to our knowledge there have been no events subsequent to December 31, 2011 which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

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

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions used in the valuations and determination of net periodic pension cost are summarized in this report.

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Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of Section 3461 of the CICA Handbook.

The preparers of the financial statements have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with Section 3461 of the CICA Handbook. We are not expressing any opinion on these assumptions.

In our opinion,

- The data on which the valuations are based are sufficient and reliable for the purposes of the valuations; and
- The calculations have been made in accordance with the requirements of Section 3461 of the CICA Handbook, reflecting application of Enbridge Gas Distribution Inc.'s accounting policies described in this report.

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

Respectfully submitted,

Allen Hornung
FSA, FCIA

03 February 2012

Date

Sarah Fitzmaurice
FSA, FCIA

03 February 2012

Date

Appendix A

Valuation Methods and Assumptions

This Appendix describes the methods and assumptions used to value the plan as well as the accounting policies used to calculate the net periodic pension cost.

Actuarial Cost Method

Accrued benefit obligations shown in this report are computed using the Projected Benefit Method Pro Rated on Services as defined in CICA 3461. The objective under this method is to expense each participant's benefits under the plan as they would accrue, taking into consideration future salary increases and the plan's benefit allocation formula. The accrued benefit is determined under this method as follows:

Under the Projected Benefit Method Pro Rated on Services an equal portion of the total estimated future benefit (i.e., with salary projection or cost escalation, where appropriate), is attributed to each year of service.

The accrued benefit obligation is the actuarial present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

The plan's **current service cost** is the sum of the individual current service costs, and the plan's **accrued benefit obligation** is the sum of the individual accrued benefit obligations for all participants under the plan.

Method for Determining Market-Related Value of Plan Assets

The market value of plan assets has been used to determine the net periodic pension cost for the fiscal year ended December 31, 2011 and for disclosure purposes as at December 31, 2011.

Accounting Policies

Management applied the Recommendations of Section 3461 of the CICA Handbook prospectively and elected to amortize the transitional (asset)/obligation on a linear basis over the average remaining service of active members expected to receive benefits under the plan.

Future salary levels and inflation affect the amount of future pensions. The projected benefit method prorated on services has been used to determine the accrued benefit obligation and current service cost.

The expected return on plan assets is based on the fair value of plan assets.

Enbridge has elected to amortize past service costs resulting from plan amendments on a linear basis over the average remaining service period of active members expected to receive benefits under the plan.

Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation and the market-related value of plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan.

Enbridge Gas Distribution Inc.'s fiscal year-end date is December 31 and the measurement date of the plan's assets and obligations is December 31. The measurement date was changed from September 30 to December 31 in fiscal 2010. The impact of this change is included as an actuarial gain/loss in the period.

Obligations are attributed to the period beginning on the employee's date of joining the plan and ending on earlier of the date of termination, death or retirement.

Summary of Assumptions

The following assumptions were used in valuing the accrued benefit obligations under the plan and the employer's net periodic pension cost.

Measurement date	▪ September 30 for the 2010 expense determination ▪ December 31 for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Discount rate	▪ 6.60% per year for the 2010 expense determination ▪ 5.70% per year for the December 31, 2010 funded status and 2011 expense determination ▪ 4.50% per year for the December 31, 2011 funded status[6]
Long-term rate of return on invested assets	▪ 7.25% per year for the 2010 and 2011 expense determination
Increases in pensionable earnings	▪ 3.50% per year
Increases in the YMPE	▪ 2.50% per year for the 2010 expense determination ▪ 2.75% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Increases in maximum pension permitted under the *Income Tax Act*	▪ 2.50% per year for the 2010 expense determination ▪ 2.75% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Consumer Price Index	▪ 2.00% per year for the 2010 expense determination ▪ 2.25% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Indexation of pensions in payment	▪ 1.10% per year in respect of Contributory service, 1.00% per year in respect of Non-Contributory and Senior Manager service for the 2010 expense determination ▪ 1.24% per year in respect of Contributory service, 1.13% per year in respect of Non-Contributory and Senior Manager service for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Mortality	UP-1994 generational mortality table using scale AA
Disability	No allowance for future disabilities
Withdrawal	See tables of sample rates
Expenses	Implicit in long-term rate of return on assets
Retirement	See table of sample rates

[6] The discount rate as of December 31, 2011 was determined in accordance with the methodology proposed by the Canadian Institute of Actuaries in September 2011.

Percentage with spouse	80% married
Age difference	A male is assumed to be 2 years older than his spouse
Headcount	No allowance made for headcount growth

Sample rates from the age related tables are summarized below:

Age	Termination - Male	Termination - Female	Retirement
20	5.0%	9.5%	0.0%
25	5.0%	13.0%	0.0%
30	5.0%	11.0%	0.0%
35	4.6%	8.5%	0.0%
40	3.0%	4.0%	0.0%
45	2.5%	3.9%	0.0%
50	1.5%	2.8%	0.0%
55	0.0%	0.0%	5.0%
56	0.0%	0.0%	5.0%
57	0.0%	0.0%	7.5%
58	0.0%	0.0%	7.5%
59	0.0%	0.0%	10.0%
60	0.0%	0.0%	20.0%
61	0.0%	0.0%	20.0%
62	0.0%	0.0%	20.0%
63	0.0%	0.0%	20.0%
64	0.0%	0.0%	20.0%
65	0.0%	0.0%	100.0%

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

Appendix B

Results by Participating Employers

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

Decmeber 31, 2011 Measurement
Enbridge Gas Distribution Pension Plans - RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	663,169,500	10,461,100	7,007,900	680,638,500
Current service cost (employer)	15,754,900	376,600	579,400	16,710,900
Interest cost	36,917,700	588,200	391,800	37,897,700
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(30,845,700)	(352,900)	(348,200)	(31,546,800)
Net transfer in (out)	196,200	(160,800)	(35,400)	-
Actuarial loss (gain)	119,244,500	2,411,100	1,718,600	123,374,200
Benefit obligation - end	804,437,100	13,323,300	9,314,100	827,074,500
Change in plan assets				
Market value of plan assets - end of prior period	718,163,500	10,690,500	6,129,900	734,983,900
Actual return on plan assets	14,090,400	216,000	125,300	14,431,700
Employer contributions	-	-	-	-
Employee contributions	-	-	-	-
Benefits paid	(30,845,700)	(352,900)	(348,200)	(31,546,800)
DC contributions paid from DB surplus	(1,211,100)	(60,700)	(73,600)	(1,345,400)
Net transfer in (out)	170,500	(138,700)	(31,800)	-
Market value of plan assets - end	700,367,600	10,354,200	5,801,600	716,523,400
Reconciliation of funded status				
Funded status - surplus (deficit)	(104,069,500)	(2,969,100)	(3,512,500)	(110,551,100)
Unamortized transitional obligation (asset)	(41,889,000)	(399,400)	(204,000)	(42,492,400)
Unamortized past service costs	2,397,900	22,900	11,700	2,432,500
Unamortized net actuarial loss (gain)	361,078,000	5,338,200	2,991,000	369,407,200
Accrued benefit asset (liability)	217,517,400	1,992,600	(713,800)	218,796,200
Components of expense				
Current service cost (including provision for plan expenses)	15,754,900	376,600	579,400	16,710,900
Interest cost	36,917,700	588,200	391,800	37,897,700
Expected return on plan assets	(50,896,800)	(762,600)	(431,600)	(52,091,000)
Amortization of transitional obligation (asset)	(24,556,700)	(234,200)	(119,600)	(24,910,500)
Amortization of past service costs	1,202,200	11,500	5,900	1,219,600
Amortization of net actuarial loss (gain)	14,546,200	216,500	124,200	14,886,900
Net expense (income)	(7,032,500)	196,000	550,100	(6,286,400)
Current Service Cost - DC	1,211,100	60,700	73,600	1,345,400

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D4
Schedule 1.8
Attachment 4
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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SERP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	13,033,200	-	-	13,033,200
Current service cost (employer)	-	-	-	-
Interest cost	718,400	-	-	718,400
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(909,600)	-	-	(909,600)
Net transfer in (out)	-	-	-	-
Actuarial loss (gain)	2,226,700	-	-	2,226,700
Benefit obligation - end	15,068,700	-	-	15,068,700
Change in plan assets				
Market value of plan assets - end of prior period	15,431,600	-	-	15,431,600
Actual return on plan assets	445,700	-	-	445,700
Employer contributions	567,800	-	-	567,800
Employee contributions	-	-	-	-
Benefits paid	(909,600)	-	-	(909,600)
Net transfer in (out)	-	-	-	-
Market value of plan assets - end	15,535,500	-	-	15,535,500
Reconciliation of funded status				
Funded status - surplus (deficit)	466,800	-	-	466,800
Employer contributions after measurement date	-	-	-	-
Unamortized transitional obligation (asset)	(390,200)	-	-	(390,200)
Unamortized past service costs	38,200	-	-	38,200
Unamortized net actuarial loss (gain)	5,366,800	-	-	5,366,800
Accrued benefit asset (liability)	5,481,600	-	-	5,481,600
Components of expense				
Current service cost (including provision for plan expenses)	-	-	-	-
Interest cost	718,400	-	-	718,400
Expected return on plan assets	(556,100)	-	-	(556,100)
Amortization of transitional obligation (asset)	(565,200)	-	-	(565,200)
Amortization of past service costs	51,000	-	-	51,000
Amortization of net actuarial loss (gain)	461,700	-	-	461,700
Net expense (income)	109,800	-	-	109,800
		-	-	
Composition of ending asset balance 12/31/2011				
Market value of RCA invested assets as per CIBC Mellon statement	7,951,500	-	-	7,951,500
Estimated value of Refundable Tax Account (RTA)	7,584,000	-	-	7,584,000
Market value of assets for disclosure	15,535,500	-	-	15,535,500

Filed: 2012-08-03
EB-2011-0354
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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SSERP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	5,909,000	-	-	5,909,000
Current service cost (employer)	-	-	-	-
Interest cost	321,000	-	-	321,000
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(493,100)	-	-	(493,100)
Net transfer in (out)	-	-	-	-
Actuarial loss (gain)	103,700	-	-	103,700
Benefit obligation - end	5,840,600	-	-	5,840,600
Change in plan assets				
Market value of plan assets - end of prior period	7,975,300	-	-	7,975,300
Actual return on plan assets	281,500	-	-	281,500
Employer contributions	-	-	-	-
Employee contributions	-	-	-	-
Benefits paid	(493,100)	-	-	(493,100)
Net transfer in (out)	-	-	-	-
Market value of plan assets - end	7,763,700	-	-	7,763,700
Reconciliation of funded status				
Funded status - surplus (deficit)	1,923,100	-	-	1,923,100
Employer contributions after measurement date	-	-	-	-
Unamortized transitional obligation (asset)	(1,900,800)	-	-	(1,900,800)
Unamortized past service costs	-	-	-	-
Unamortized net actuarial loss (gain)	1,693,500	-	-	1,693,500
Accrued benefit asset (liability)	1,715,800	-	-	1,715,800
Components of expense				
Current service cost (including provision for plan expenses)	-	-	-	-
Interest cost	321,000	-	-	321,000
Expected return on plan assets	(279,500)	-	-	(279,500)
Amortization of transitional obligation (asset)	(245,300)	-	-	(245,300)
Amortization of past service costs	-	-	-	-
Amortization of net actuarial loss (gain)	57,800	-	-	57,800
Net expense (income)	(146,000)	-	-	(146,000)
Composition of ending asset balance 12/31/2011				
Market value of RCA invested assets as per CIBC Mellon statement	2,715,400	-	-	2,715,400
Estimated value of EBP invested assets as per CIBC Mellon statement	2,541,900	-	-	2,541,900
Estimated value of Refundable Tax Account (RTA)	2,506,400	-	-	2,506,400
Market value of assets for disclosure	7,763,700	-	-	7,763,700

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Appendix C

Additional Disclosures

Enbridge Gas Distribution

	2011				
	EGD RPP	EGD DC	EGD SERP	EGD SSERP	Total
Additional year-end information					
1. Sensitivity to key assumptions					
a. Half a percent decrease in expected return on assets					
i. Effect on pension expense	3,592,000	n/a	38,000	19,000	3,649,000
ii. Effect on year-end accrued benefit obligation	n/a	n/a	n/a	n/a	n/a
b. Half a percent decrease in discount rate					
i. Effect on pension expense	6,276,000	n/a	126,000	2,000	6,404,000
ii. Effect on year-end accrued benefit obligation	59,730,000	n/a	733,000	239,000	60,702,000
b. Half a percent decrease in rate of salary increase					
i. Effect on pension expense	(1,612,000)	n/a	(15,000)	-	(1,627,000)
ii. Effect on year-end accrued benefit obligation	(7,578,000)	n/a	(59,000)	-	(7,637,000)
2. Expected DB benefit payments					
31-Dec-2011 :					
31-Dec-2012 :	32,686,000	n/a	944,000	531,000	34,161,000
31-Dec-2013 :	33,993,000	n/a	982,000	552,000	35,527,000
31-Dec-2014 :	35,353,000	n/a	1,021,000	574,000	36,948,000
31-Dec-2015 :	36,767,000	n/a	1,062,000	597,000	38,426,000
31-Dec-2016 :	38,238,000	n/a	1,104,000	621,000	39,963,000
Next five years	215,397,000	n/a	6,220,000	3,500,000	225,117,000
3. Expected contributions in following year	16,952,000	1,497,000	677,000	-	19,126,000

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - RPP

Expected benefit payments				
31-Dec-2012 :	32,001,000			
31-Dec-2013 :	33,281,000			
31-Dec-2014 :	34,612,000			
31-Dec-2015 :	35,996,000			
31-Dec-2016 :	37,436,000			
Next five years	210,873,000			
Expected contributions				
31-Dec-2012 :	15,959,000	407,000	586,000	16,952,000
31-Dec-2013 :	33,169,000	685,000	783,000	34,637,000
31-Dec-2014 :	29,583,000	635,000	762,000	30,980,000
31-Dec-2015 :	26,697,000	596,000	750,000	28,043,000
31-Dec-2016 :	24,395,000	567,000	746,000	25,708,000
31-Dec-2017 :	22,586,000	545,000	746,000	23,878,000
31-Dec-2018 :	21,188,000	531,000	752,000	22,471,000
31-Dec-2019 :	17,271,000	441,000	634,000	18,344,000
31-Dec-2020 :	14,187,000	362,000	521,000	15,069,000
31-Dec-2021 :	14,689,000	375,000	540,000	15,603,000

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SERP

Expected benefit payments				
31-Dec-2012 :	944,000			
31-Dec-2013 :	982,000			
31-Dec-2014 :	1,021,000			
31-Dec-2015 :	1,062,000			
31-Dec-2016 :	1,104,000			
Next five years	6,220,000			
Expected contributions				
31-Dec-2012 :	677,000	-	-	677,000
31-Dec-2013 :	695,000	-	-	695,000
31-Dec-2014 :	176,000	-	-	176,000
31-Dec-2015 :	121,000	-	-	121,000
31-Dec-2016 :	77,000	-	-	77,000
31-Dec-2017 :	42,000	-	-	42,000
31-Dec-2018 :	14,000	-	-	14,000
31-Dec-2019 :	-	-	-	-
31-Dec-2020 :	-	-	-	-
31-Dec-2021 :	-	-	-	-

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Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SSERP

Expected benefit payments				
31-Dec-2012 :	531,000			
31-Dec-2013 :	552,000			
31-Dec-2014 :	574,000			
31-Dec-2015 :	597,000			
31-Dec-2016 :	621,000			
Next five years	3,500,000			
Expected contributions				
31-Dec-2012 :	-	-	-	-
31-Dec-2013 :	-	-	-	-
31-Dec-2014 :	-	-	-	-
31-Dec-2015 :	-	-	-	-
31-Dec-2016 :	-	-	-	-
31-Dec-2017 :	-	-	-	-
31-Dec-2018 :	-	-	-	-
31-Dec-2019 :	-	-	-	-
31-Dec-2020 :	-	-	-	-
31-Dec-2021 :	-	-	-	-

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Appendix D

Employer Certification

With respect to the Actuarial Valuation Report on Pension Expense and Employer Disclosure for the Fiscal Year Ending December 31, 2011 Under CICA Section 3461 of the Enbridge Gas Distribution Inc. Retirement Plans, I hereby certify that, to the best of my knowledge and belief:

- the membership data supplied to the actuary provide a complete and accurate description of all persons who are entitled to benefits under the terms of the plan for service up to the date of the valuation;
- a copy of the official plan documents and of all amendments made up to December 31, 2011 were supplied to the actuary;
- all substantive commitments (as defined under CICA 3461) have been communicated to the actuary;
- accounting policies as adopted by the company are those described in this report.
- the actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- the management best estimate assumptions for purposes of the valuations and the extrapolation of the financial position of the plan as of the fiscal year end December 31, 2011 are those described in this report; and
- all events subsequent to the valuation that may have an impact on the results of the valuation or of a future valuation have been communicated to the actuary.

February 13, 2012.
Date

J L Whelan.
Signed

John K. Whelan.
Name

Sr. Vice President & Controller
Title

Signed

SONIA HEROUX
Name

SR. MANAGER PENSION AND BENEFITS
Title

MERCER

Mercer (Canada) Limited
222 – 3rd Avenue South West
Suite 1200
Calgary, Alberta T2P 0B4
403 269 4945

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BOARD STAFF INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref(1): Ex. A2/Tab3/Sch 1/Appendix 4 Mercer Report, Updated Estimated 2013-2017 Cash Costs – EGD Non-Pension Post-Retirement Plans – 19 January 2012

Ref(2): Ex. A2/Tab3/Sch 1/Appendix 5 Mercer Report, Updated Estimated 2013-2017 Accrual Funding Costs – EGD Non-Pension Post-Retirement Plans – 19 January 2012

a) Has EGD's external auditor audited or reviewed Appendix 4 and Appendix 5 prepared as at January 19, 2012, including the assumptions used?

   i. If so, do the reports reflect the auditor's comments?
   ii. If not, when will the external auditor's audit or review take place?

b) Have these documents been filed with the FSCO or CRA?

   i. If so, have comments been received form the FSCO or CRA?

RESPONSE

a) No, the external auditor has not reviewed Appendix 4 or 5. These reports contain estimates for the periods 2013 through 2017 which EGD's external auditor would not have reviewed as it would not impact actual year end results. As actual OPEB expense arises in the years 2013 to 2017 EGD's external auditor will review any supporting Mercer reports at that time.

b) No, these documents have not been filed as it is not a FSCO or CRA filing requirement.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 1

EGD is proposing to switch to the accrual basis from the cash basis for regulatory purposes for OPEB in this proceeding, effective January 1, 2013.

a) Please confirm that the cash basis cannot be used for financial reporting purposes for OPEB under USGAAP.

   i. If this is not the case, please list the advantages and disadvantages to ratepayers and to EGD if the cash basis is used for both financial reporting and regulatory purposes for OPEB.

b) EGD has listed the general benefits of using the accrual basis for OPEB or financial reporting purposes and regulatory purposes at Ex. A2/ Tab 3/ Sch 1/ Page 7. Please specifically list the advantages and disadvantages to ratepayers and to EGD if the accrual basis is used for both financial reporting and regulatory purposes for OPEB.

c) If the accrual basis is used for financial reporting purposes and the cash basis is used for regulatory purposes for OPEB, please list the advantages and disadvantages to ratepayers and to EGD.

RESPONSE

a) Confirmed.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

b) In addition to what has already been filed in Exhibit A2, Tab 3, Schedule 1, another advantage to ratepayers would be that the use of the accrual basis for both financial reporting and regulatory purposes for OPEB would result in consistency between financial and regulatory accounting and therefore not require the administrative burden of reconciling financial accounting and regulatory accounting.

c) If the accrual basis is not allowed for both financial and regulatory purposes, EGD would not be allowed to record the differing amounts of the accrual basis and the formerly permitted cash method in its financial accounting records balance sheet. However, EGD would be required within a second set of regulatory accounting records to record and reconcile the differing amounts for determining what has been recovered in rates and what remains to be recovered. EGD's corporate financial accounting records would show lower earnings and a reduced level of equity when compared to regulatory accounting records which would create unnecessary confusion within financial accounting records for interpretation purposes. Ultimately this treatment would result in EGD and its ratepayers being faced with the same disadvantages associated with the use of International Financial Reporting Standards, which EGD explained and the OEB approved would be averted by allowing USGAAP for regulatory purposes.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 1

EGD did not apply to the Board to switch from the cash to accrual basis for OPEB for regulatory purposes in 2000 when the CICA Handbook changed. EGD also had the opportunity to apply to the Board to switch to the accrual basis for OPEB for regulatory purposes in 2009 when the CICA Handbook change impacted rate-regulated companies.

a) Please explain why EGD did not make an application to the Board to switch to the accrual basis for OPEB for regulatory purposes both in 2000 and 2009.

b) Please provide reasons why the Board should grant EGD's request to switch to the accrual basis for OPEB for regulatory purposes effective January 1, 2013, in light of the fact that EGD had the opportunity to bring the matter before the Board both in 2000 and 2009.

RESPONSE

a) In accordance with CICA handbook paragraphs 1100.34-.35 Enbridge and other rate regulated utilities were exempted from CICA Handbook section 3461, introduced in 2000, which required Canadian companies to adopt accrual accounting for OPEB with regulatory approval. That is, Enbridge and other regulated utilities were able to continue recording OPEB on a cash basis with no recognition of the OPEB liability in the financial statements where their regulator approved of the recovery of costs expensed under the cash method. Given that the difference between methods was purely an issue of when the same costs to be paid out in the future would be recognized and that the Board was approving the recovery of such costs both on an

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

accrual and cash basis for regulated entities, it was reasonable for EGD to interpret the exemption requiring the Company to switch to the accrual basis. In fact in the recent Ontario Power Generation ("OPG") EB-2010-0008 proceeding, the Board in its findings within its Decision stated:

> OPG correctly points out that there is no consistency amongst utilities in the use of either the cash or accrual method to setting pension and other post-employment benefit expenses. Both methodologies have been approved by the Board.

In 2009, as stated in EB -2011-0277 Exhibit I, Tab 1, Schedule 16, response d), it was and is EGD's view that the cash basis of accounting for OPEB continued to be acceptable, and maintained consistency between the financial reporting and regulatory treatment of OPEB costs. In addition and regardless of Enbridge's view, in 2008, the Board initiated a consultative for the purpose of ensuring an appropriate framework for rate regulation would be understood for a required transition to IFRS accounting standards in 2011 and thereafter.

The Board was looking to determine what to do from a ratemaking perspective in respect of regulated entities having to convert away from Canadian Generally Accepted Accounting Principles ("CGAAP") to International Financial Reporting Standards ("IFRS") commencing in 2011. In order to determine a regulatory treatment framework the Board required an understanding of the total potential financial reporting implications of the required accounting standards change before it would allow any ratemaking changes in association with the accounting standards changes. In a letter from the Board on July 24, 2008, the objectives, deliverables and approach of the planned consultative were set out. Within the deliverables, it was stated that "Board Staff anticipates that any substantive modifications to the Board's regulatory instruments will only be made by the Board following the appropriate consultation process". It was clear to Enbridge, who were active participants within the consultative through 2008 and 2009 and within the IFRS working group in 2010 and 2011, that the Board was looking to understand the total potential impact for ratemaking as a result of understanding all of the changes being required by IFRS. The existence and mandate of the IFRS consultative would not permit Enbridge or any regulated entity to seek a change in rates in relation to one anticipated element of change being caused by the IFRS accounting standards change without first knowing the impact of all the elements of the standards change.

As a result, it can be seen that the Company could not have requested the use of accrual accounting for OPEB's for 2009.

b) See the response to part a).

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #12

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref(1): Ex. A2/ Tab 3/ Sch 1
Ref(2): Ex. M1/ Tab 1/ Sch 4

Please describe the regulatory tax implications generated from the following, specifically the impact on the regulatory tax provision in the 2013 Test Year:

a) EGD's proposed switch from the cash basis to the accrual basis for OPEB for regulatory purposes
b) EGD utilizing the cash basis for OPEB for regulatory purposes
c) EGD utilizing the accrual basis for OPEB for regulatory purposes

RESPONSE

Please see the response to Board Staff Interrogatory #6 at Exhibit I, Issue D4, Schedule 1.6.

Witnesses: S. Chhelavda
K. Culbert

BOARD STAFF INTERROGATORY #13

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: Ex. A2/ Tab 3/ Sch 1

a) Please provide the full actuarial valuation report as at December 31, 2009 for OPEB and the accounting valuation report as at December 31, 2011.

b) Please confirm if EGD's external auditors have audited or reviewed the reports, including the assumptions used. Please provide supporting documentation.

   i. If so, do the reports reflect the auditor's comments?
   ii. If not, when will the external auditor's audit or review take place?

RESPONSE

a) A copy of EGD's December 31, 2011 accounting valuation report is provided as Attachment A. EGD is not required to file a full actuarial valuation report for OPEB, therefore a December 31, 2009 full actuarial valuation report does not exist and cannot be provided.

b) Please refer to EGD's response to Board Staff Interrogatory #7, part b), at Exhibit I, Issue D4, Schedule 1.7.

   i. and ii. Please refer to EGD's response to Board Staff Interrogatory #7, part b) i), at Exhibit I, Issue D4, Schedule 1.7.

Witnesses: K. Culbert
S. Chhelavda

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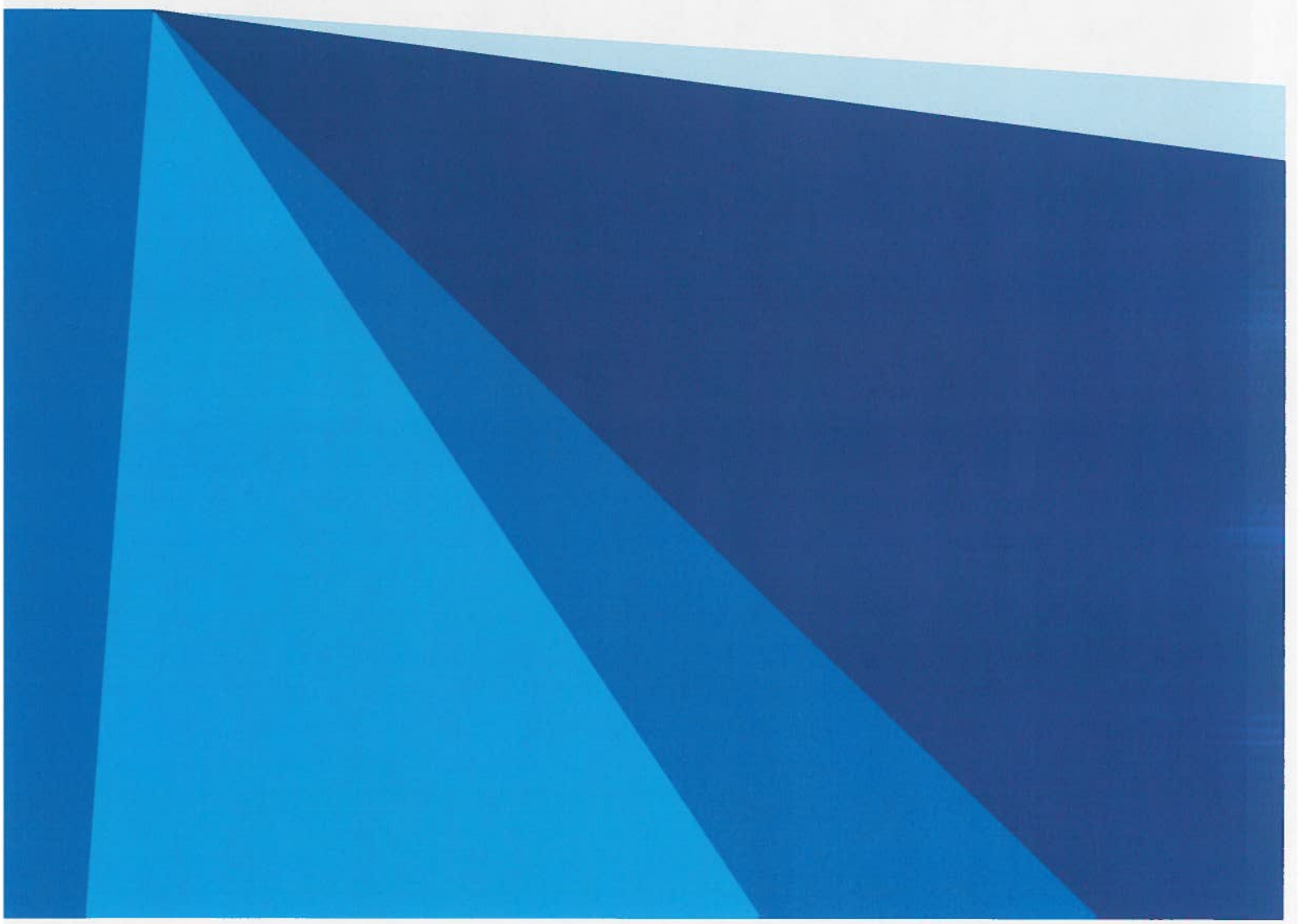
REPORT ON NON-PENSION POST RETIREMENT BENEFIT COST AND DISCLOSURE FOR THE FISCAL YEAR ENDING 31 DECEMBER 2011 UNDER CICA SECTION 3461

ENBRIDGE GAS DISTRIBUTION INC.

14 FEBRUARY 2012



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Report Highlights

This report has been prepared by Mercer (Canada) Limited at the request of Enbridge Gas Distribution Inc. This report provides information on non-pension post retirement obligations and benefit cost calculated in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3641") to enable Enbridge Gas Distribution Inc. to satisfy accounting and disclosure requirements for financial statements pursuant to CICA 3461.

Prior to 01 January 2009, due to regulatory requirements, the Company was not actually recognizing the benefit costs on an accrual basis. We have not been asked to reconcile the CICA 3461 benefit costs to the actual costs recognized by the Company within their financial statements. As a result, a reconciliation is not included in this report.

The Non-Pension Post Retirement Benefit Plan is a defined benefit plan funded on a cash basis by contributions from Enbridge Gas Distribution Inc. and consists of a defined benefit component and a retiree health spending account component.

Enbridge Gas Distribution Inc.'s fiscal year-end date is 31 December and the measurement date for the 2010 and 2011 year-end plan obligations as described in this report is 31 December.

All results presented in this report are in Canadian dollars.

This report also presents information for the fiscal year ending 31 December 2010 for comparative purposes. In addition, Appendix F provides the results by participating employer.

Fiscal Year Ending 31 December 2011

The benefit cost (also referred to as expense in this report) calculated in accordance with CICA 3461 for the fiscal year ending 31 December 2011 is a charge of $9,106,000.

The Accrued Benefit Liability as calculated in accordance with CICA 3461 is $75,508,000.

The estimated employer contributions and employer-paid benefit payments during the fiscal year ending 31 December 2011 were $3,402,000.

It should be noted that future health care cost trends are especially difficult to predict and actual experience is likely to differ from expected. The use of a health care cost trend of 1% per year above the assumptions used in this valuation for the fiscal year ending 31 December 2011 would result in an increase to the Accrued Benefit Obligation (ABO) calculated in accordance with CICA 3461 of approximately 15%.

Changes in Plan Provisions

There were no changes in plan provisions since the last disclosure as of 31 December 2010.

Changes in Actuarial Assumptions

There have been changes in actuarial assumptions since the last disclosure as of 31 December 2010. Please refer to the Summary of Assumptions in Appendix C of this report for a description of these changes.

Changes in Actuarial Methods

There were no changes in actuarial methods since the last disclosure as of 31 December 2010.

Changes in Accounting Policies

The measurement date was changed from 30 September to 31 December in fiscal 2010. The impact of this change is included as an actuarial gain/loss in the period. There were no changes in accounting policies since the last disclosure as of 31 December 2010.

Transition to US Accounting Standards

Enbridge will be adopting US accounting standards on January 1, 2012. Due to the requirement to provide comparative information in the first set of financial statements, Enbridge will transition to US accounting standards from current Canadian GAAP on January 1, 2011. On that date, a transition adjustment will be made to retained earnings to bring the existing current CICA 3461 balances in line with the requirements of US accounting standards. Enbridge will continue to report under current Canadian GAAP in 2011. Two sets of financial results will be maintained for 2011, one for current Canadian GAAP and another one for US accounting standards. In 2012, current Canadian GAAP will cease to exist and US accounting standards will commence with comparative information for 2011.

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Principal Expense and Disclosure Information

A summary of the principal expense and disclosure information, required pursuant to CICA 3461, for the current fiscal year and the prior fiscal year follows.

Components of Benefit Cost	Fiscal Year Ending 31 December 2011	Fiscal Year Ending 31 December 2010
Current service cost	$1,321,000	$1,117,000
Interest cost	4,616,000	4,890,000
Actual return on plan assets	0	0
Actuarial loss (gain)	13,767,000	5,092,000
Plan amendments	0	0
Costs arising in the period	**$19,704,000**	**$11,099,000**
Differences between costs arising in the period and costs recognized in the period in respect of:		
• Return on plan assets	0	0
• Actuarial loss (gain)	(13,767,000)	(5,133,000)
• Plan amendments	0	0
• Transitional obligation (asset)	3,169,000	3,169,000
Benefit cost recognized	**$9,106,000**	**$9,135,000**

Weighted-Average Assumptions for Expense	Fiscal Year Ending 31 December 2011	Fiscal Year Ending 31 December 2010
Discount rate	5.70%	6.60%
Initial weighted average health care trend rate	6.97%[1]	7.15%
Ultimate weighted average health care trend rate	4.50%	4.50%
Year ultimate rate reached	2029	2029

[1] Trend rate applied to the 2010 claim cost (31 July 2010 mid-point) to trend the claim cost forward twelve months to 31 July 2011 mid-point.

Weighted-Average Assumptions for Disclosure	31 December 2011	31 December 2010
Discount rate	4.50%	5.70%
Initial weighted average health care trend rate	6.74%[2]	6.97%[1]
Ultimate weighted average health care trend rate	4.50%	4.50%
Year ultimate rate reached	2029	2029

Change in Accrued Benefit Obligation (ABO)	Fiscal Year Ending 31 December 2011	Fiscal Year Ending 31 December 2010
ABO at end of prior year	$82,685,000[3]	$75,739,000[4]
Current service cost	1,321,000	1,117,000
Interest cost	4,616,000	4,890,000
Benefits	(3,402,000)	(4,153,000)[5]
Actuarial loss (gain)	13,767,000	5,092,000[6]
ABO at end of year	**$98,987,000[7]**	**$82,685,000[8]**

Change in Plan Assets	Fiscal Year Ending 31 December 2011	Fiscal Year Ending 31 December 2010
Fair value of plan assets at end of prior year	**$0**	**$0**
Actual return on plan assets	0	0
Employer contributions	3,402,000	4,153,000[5]
Benefits	(3,402,000)	(4,153,000)[5]
Fair value of plan assets at end of year	**$0**	**$0**

[2] Trend rate applied to the 2011 claim cost (31 July 2011 mid-point) to trend the claim cost forward twelve months to 31 July 2012 mid-point.

[3] Based on membership data as of 01 January 2009, projected to 30 December 2010.

[4] Based on membership data as of 01 January 2009, projected to 30 September 2009.

[5] Total estimated benefit payments/employer contributions of $4,153,000 for fiscal year ending 31 December 2010 includes estimated contributions made from 01 October 2010 to 31 December 2010 of $851,000

[6] Total actuarial loss of $5,092,000 for fiscal year ending 31 December 2010 includes a loss from change in measurement date of $851,000

[7] Based on membership data as of 01 January 2009, projected to 31 December 2011.

[8] Based on membership data as of 01 January 2009, projected to 30 December 2010.

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	Fiscal Year Ending 31 December 2011	Fiscal Year Ending 31 December 2010
Funded status at end of year	**($98,987,000)**	**($82,685,000)**
Employer contributions during period from measurement date to fiscal year end	0	0
Unamortized transitional obligation (asset)	12,674,000	15,843,000
Unamortized past service costs	0	0
Unamortized net actuarial loss (gain)	10,805,000	(2,962,000)
Accrued benefit asset (liability)	**($75,508,000)**	**($69,804,000)**

Effect of Change in Assumed Health Care Cost Trend Rates	Fiscal Year Ending 31 December 2011	Fiscal Year Ending 31 December 2010
Effect on aggregate of current service cost and interest cost		
• One-percentage point increase	$810,000	$756,000
• One-percentage point decrease	($653,000)	($619,000)
Effect on ABO at fiscal year end		
• One-percentage point increase	$15,038,000	$12,023,000*
• One-percentage point decrease	($12,127,000)	($9,785,000)*

* As measured on 30 September 2010

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Certification

We have prepared an actuarial valuation of Enbridge Gas Distribution Inc.'s benefit obligations for accounting purposes as at 01 January 2009 and extrapolated those results to 31 December 2010. In accordance with our mandate, the purpose of this valuation and extrapolation is to determine the benefit cost of the Plan in accordance with CICA 3461 for the fiscal year beginning 01 January 2011 and ending 31 December 2011 to enable the Company to account for the cost of the Plan under CICA 3461.

In addition, we have prepared a second actuarial valuation of Enbridge Gas Distribution Inc.'s benefit obligations for accounting purposes as at 01 January 2009 and extrapolated those results to 31 December 2011. In accordance with our mandate, the purpose of this valuation and extrapolation is to determine the obligations of the Plan in accordance with CICA 3461 to enable the Company to satisfy the disclosure requirements under CICA 3461.

This report has been prepared exclusively for Enbridge Gas Distribution Inc. This valuation report may not be relied upon for any purpose other than what is described in this report or by any party other than Enbridge Gas Distribution Inc. and its auditors. Mercer is not responsible for the consequences of any other use.

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

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

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

Plan Provisions

The results of the valuations set forth in this report reflect the provisions of the Plan as of the dates of the extrapolations as reported to us by Management.

The Plan has not been amended since the last extrapolation for accounting purposes as at 31 December 2010. A summary of the plan provisions is provided in Appendix D of this report. These plan provisions have been certified by Enbridge Gas Distribution Inc. under Employer Certification in Appendix E of this report.

There was no substantive commitment reported to us by Management.

Data

The valuations and extrapolations are based on membership data as at 01 January 2009 provided by Enbridge Gas Distribution Inc. The membership data is summarized in Appendix B of this report.

Subsequent Events

Based on discussions with representatives of Enbridge Gas Distribution Inc., to our knowledge there have been no events subsequent to 31 December 2011 which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions used in the valuations and determination of benefit cost are summarized in Appendix C of this report.

Valuation methods and assumptions are the same as the prior year's valuation with the exception of the following (all changes were made at the end of the fiscal year):

- The discount rate changed from 5.70% to 4.50%.
- The average claim per retiree has been updated to reflect average claim costs for the period 01 July 2009 to 30 June 2011. Details of these claim costs can be found in Appendix C of this report.
- Insurer expenses have been updated to reflect current charges.

Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future valuations and will affect future benefit cost.

Actuarial computations in accordance with CICA 3461 are for purposes of enabling Enbridge Gas Distribution Inc. to fulfill accounting requirements pursuant to CICA 3461. Determination for purposes other than meeting employer financial accounting requirements may be significantly different from the results reported herein. Accordingly, additional determinations are needed for other purposes such as adequacy of funding for the ongoing plan, purchase price calculations or plan design costings.

Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of CICA 3461.

The preparers of the financial statements have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best-estimate assumptions, selected for accounting purposes, in accordance with CICA 3461. These assumptions are in accordance with accepted actuarial practice.

In my opinion,

- The data on which the valuations are based is sufficient and reliable for the purposes of the valuations, and
- The calculations have been made in accordance with the requirements of CICA 3461 reflecting application of Enbridge Gas Distribution Inc.'s accounting policies described in this report.

This report has been prepared and my opinion given, in accordance with accepted actuarial practice in Canada.

Respectfully submitted,

Nicholas H. Gubbay, F.C.I.A , F.F.A.

14 February 2012

Date

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APPENDIX A

Additional Information

This information provides additional information request by Enbridge Gas Distribution Inc.

Projected Benefit Payments

The following table provides the projected benefit payments from 2012 to 2016 and the following five years in aggregate.

Year	EGD
2012	$3,590,000
2013	$3,842,000
2014	$4,117,000
2015	$4,394,000
2016	$4,678,000
2017 - 2021	$26,556,000

Sensitivity Analysis

The following tables provide the sensitivity of the 2011 benefits expense and 2011 year-end accrued benefit obligation (ABO) to a 0.5% decrease in the discount rate and expected return on assets assumptions.

	Discount Rate Decrease of 0.5%	
	Change in 2011 Benefits Expense	Change in 2011 Year-End ABO
Enbridge Gas Distribution Inc.	$53,000	$7,623,000

Although the Enbridge Gas Distribution Inc. post retirement benefit plan has salary-related life insurance benefits, the impact of a 0.5% decrease to the salary scale assumption is less than the Company's materiality level on both the accrued benefit obligation and the 2011 benefit expense.

As there are no assets associated with the plans, the expected return on plan assets assumption is not relevant.

APPENDIX B

Membership Data

The actuarial valuations are based on membership data as at 01 January 2009, provided by Enbridge Gas Distribution Inc.

We have not independently verified the accuracy or completeness of the data except to the extent required by generally accepted professional standards and practices. Mercer will not be held responsible for any liability arising from the use of incomplete, inaccurate or not up-to-date data or documentation. We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), earnings, and service. The results of these tests were satisfactory.

Plan membership data are summarized below.

Analysis of Membership Data

Active Membership Data

	01 January 2009			
	Number	Average Age	Average Service	Average Salary
Grandfathered Plan				
Non Union	389	54.5	27.6	$83,448
Union	360	54.4	26.4	$58,205
Part Time	4	60.3	11.3	$30,519
Non-Grandfathered Plan	1,294	39.9	7.7	$69,578
Total	2,047	45.3	14.8	$70,137

Inactive Membership Data

	01 January 2009		
	Less than age 65	Greater than age 65	Total
Grandfathered Plan			
Number of Retirees	253	844	1,097
Average age of Retirees	60.8	74.3	71.2
Average Life Benefit	$100,765	$5,000	$27,086
Number of Spouses of Retirees	278	577	855
Average age of Spouses	58.7	73.2	68.5
Number of Surviving Spouses	29	145	174
Average Age of Surviving Spouses	56.4	77.0	73.6
Non-Grandfathered Plan			
Number of Retirees			13
Average age of Retirees			60.2
Average Life Benefit			$10,000
Number of Spouses of Retirees			11
Average age of Spouses			60.5

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

Reconciliation of Membership

	Actives	Retirees	Surviving Spouses	Total
Total at 01 January 2008	**2,106**	**1,084**	**170**	**3,360**
New entrants	88	0	16	104
Terminations/Deaths	(90)	(31)	(12)	(133)
Retirements	(57)	57	0	0
Total at 01 January 2009	**2,047**	**1,110**	**174**	**3,331**

The distribution of the active members by age and completed years of service as at 01 January 2009 is summarized as follows:

Distribution of Active Members
By Age Group and Completed Years of Service as at 01 January 2009

	Years of Completed Service							
Age	**0–4**	**5–9**	**10–14**	**15–19**	**20–24**	**25–29**	**30+**	**Total**
20 – 24	22							22
25 – 29	145	34						179
30 – 34	90	56	10	1				157
35 – 39	93	66	45	24	1			229
40 – 44	89	64	26	75	50	4		308
45 – 49	75	46	38	70	67	53	4	353
50 – 54	40	37	30	46	47	91	90	381
55 – 59	17	18	8	28	30	66	115	282
60 – 64	8	7	7	18	20	22	43	125
65 +		1		2	2	2	4	11
Total	**579**	**329**	**164**	**264**	**217**	**238**	**256**	**2,047**

The distribution of inactive members by age as at 01 January 2009 is summarized as follows:

Distribution of Retirees and Surviving Spouses By Age Group as at 01 January 2009

Age	**Number**
Under 55	9
55 – 59	91
60 – 64	192
65 – 69	271
70 – 74	259
75 – 79	221
80 – 84	142
85 – 89	73
90 – 94	17
95+	9
Total	**1,284**

APPENDIX C

Valuation Methods and Assumptions

This Appendix describes the methods and assumptions used to value the Plan as well as accounting policies used to calculate the benefit cost.

Cost Method

ABO numbers shown in this report are computed using the Projected Benefit Method Pro Rated on Service, as defined in CICA 3461. The objective under this method is to expense each member's benefits under the plan as they accrue, taking into consideration projections of benefit costs to and during retirement. The ABO is determined under this method as follows:

Under the Projected Benefit Method Pro Rated on Service, an equal portion of the total estimated future benefit is attributed to each year of service.

The ABO is the actuarial present value of the accrued benefit as of the valuation date and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

For retirees, spouses and surviving spouses, the ABO is the present value of all future projected benefits.

For each active member, a "full eligibility" date is determined as the first date the member has or will have met the age and service requirements to qualify for all benefits after retirement. For grandfathered plan members, full eligibility is age 55. For non-grandfathered plan members, eligibility is 55 with 5 years of continuous service.

For active members who have reached "full eligibility", the ABO is the present value as of the valuation date of all future projected benefits. For these members, the service cost is zero.

For active members who have not yet reached "full eligibility", the ABO is the present value of all future projected benefits, multiplied by the ratio of service at the valuation date to projected service at "full eligibility". For these members, the current service cost is the present value of benefits as of the valuation date deemed to accrue in the fiscal year, and is determined as the present value of all future projected benefits divided by the projected service at "full eligibility".

The plan's **current service cost** is the sum of the individual current service costs, and the plan's **ABO** is the sum of the individual ABOs for all members under the plan.

Funding Policy

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The Company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

Accounting Policies

Management applied the Recommendations of CICA 3461 prospectively and elected to amortize the transitional obligation on a linear basis from 01 January 2000 over the average remaining service period of active members expected to receive benefits under the plan (15 years as of 01 October 2000).

Cumulative gains and losses in excess of 10% of the beginning of year ABO are amortized over the expected average remaining service of active members expected to receive benefits under the plan (12.7 years).

Obligations are attributed to the period beginning on the member's date of hire and ending on the date the member reaches first full eligibility for benefits.

Enbridge Gas Distribution Inc.'s fiscal year-end date is 31 December and the measurement date for the 2010 and 2011 year-end plan obligations as described in this report is 31 December.

We have used claims and expense data submitted by Sun Life Assurance Company of Canada without further audit and participant data as supplied by Enbridge Gas Distribution Inc. We have reviewed the information for internal consistency, and we have no reason to doubt its substantial accuracy.

Summary of Assumptions

The following assumptions were used in valuing the benefit obligations under the Plan.

Measurement date	31 December	
Discount rate	• 6.60% per annum for the 2010 benefit cost determination • 5.70% per annum for 31 December 2010 funded status and 2011 benefit cost determination • 4.50% per annum for 31 December 2011 funded status	
Salary increases	5.00% per annum	
Medical cost trend rates	Hospital	4.50% per annum
	Prescription drugs	9.375% per annum in 2009 grading down to 4.50% per annum in and after 2029. The trend rates are reduced by 0.5% per year after age 65 for Ontario members to reflect the inclusion of the Ontario Drug Benefit costs
	Other medical	4.50% per annum
	Vision care	4.50% per annum, with an effective 0% per annum net trend rate due to the low fixed dollar limit that exists for the benefit
Provincial health trend rate (non-grandfathered)	0.00% per annum	

Retiree HSA trend rate	0.00% per annum
Dental cost trend rate	4.50% per annum
Mortality	Uninsured Pensioners' (UP) Table for 1994 with generational mortality improvements
Withdrawal	Rates at sample ages are shown below:

Age	Male	Female
25	5.0%	13.0%
35	4.6%	8.5%
45	2.5%	3.9%
55	0.0%	0.0%

No withdrawal assumed after attainment of eligibility for retirement.

Disability incidence	No explicit allowance has been made for disability prior to retirement.
Retirement rates	If 30 years of continuous service is not reached between ages 55 and 59 inclusive, then the table rates apply, otherwise 20% of the members will retire at the first age at which 30 years of continuous service and age 55 are reached. At all other ages, rates follow the table below.

Age	Rate
55 – 56	5.0%
57 – 58	7.5%
59	10.0%
60 – 64	20.0%
65	100.0%

Marital status	For active members, 80% are assumed to be married at retirement with males assumed to be 2 years older than their female spouses. For current retirees, actual marital status and spousal age is assumed.		
2009 Age 65 per capita claims costs excluding administration and taxes	Hospital	$71	(from $70 last valuation)
	Prescription drugs	$902	(from $998 last valuation)
	Other medical	$134	(from $127 last valuation)
	Vision care	$15	(from $16 last valuation)
	Dental care	$516	(from $489 last valuation)
	Total	$1,638	(from $1,700 last valuation)
	The current per capita medical and dental costs were based on actual claims experience from 01 July 2009 to 30 June 2011 and adjusted to the midpoint of the valuation year. Drug costs are shown before the impact of any provincial drug plan.		
Provincial Health Premiums	The company pays 50% of the cost of provincial health premiums (shown below) for non-grandfathered retirees in British Columbia. We have incorporated the cost of these premiums in our valuation. Monthly premiums Single $54 Family $96. The Company cost is frozen at the above (2004) levels.		

Increases in utilization by age	Cost at Age					
	Attained Age	Hospital	Drug	Other Medical	Dental	Vision
	55	45%	75%	106%	106%	106%
	60	64%	88%	103%	104%	103%
	65	100%	100%	100%	100%	100%
	70	161%	109%	102%	95%	97%
	75	253%	113%	110%	90%	95%
	80	388%	114%	121%	83%	92%
Prescription drug offset assumption at age 65 and after	The following cost-offsets were assumed to reflect the impact of provincial drug plans: Québec: 50% Ontario 65% Alberta: 55% Prince Edward Island 35% All other provinces: 0%					
Administrative expenses as a percentage of paid claims	Medical	5.00% plus 2.28% for stop loss charge (from 3.70% plus 1.474% for stop loss charge last valuation) plus applicable taxes				
	Dental	5.00% (from 4.60% last valuation) plus applicable taxes				
	Retiree HSA	5.00% (from 5.30% last valuation) plus applicable taxes				
	Life insurance	2.50% (from 4.80% last valuation) plus applicable taxes				
Taxes	Premium Tax Quebec – 2.55% (from 2.35% last valuation) Other – 2.00% Retail Sales Tax Quebec – 9.00% Ontario – 8.00%					
Participation	100% of members are assumed to participate in the retiree health plan.					

Claims Cost Development

The per covered member claim costs used in the 01 January 2009 valuation and extrapolated for purposes of determining the liabilities as at 31 December 2011 were based on the actual retiree and dependent claims information for the two year period, 01 July 2009 to 30 June 2011, increased with assumed health care cost trend rates to 2011. The claims experience was collected and analyzed separately for Hospital, Prescription Drug, Vision Care, Other Medical and Dental benefits.

A description of the process used to set the "Age 65 per capita claims costs" (shown in Appendix C – Summary of Assumptions) is as follows:

- For each plan year (July 01 to June 30) of claims, a cost per covered member was developed by dividing the total annual claims by the total number of eligible retirees, and dependents covered during the year.

- This cost per person has been adjusted to the cost per covered member at age 65 based on the individual ages of the covered members using the "Increases in utilization by age" assumptions shown in Appendix C – Summary of Assumptions.
- These costs have been increased to include the cost of insurance company administrative expenses and provincial taxes charged on the claims.
- The costs are then increased with assumed health care cost trend rates from the claims experience year to the midpoint of the valuation year of 01 July 2011.
- As indicated, this analysis was performed for each of the two plan years used. The assumed cost per covered member for the valuation was based on a weighted average of the costs for the two plan years with 50% weighting given to each of the two plan years.

Effect of Plan Maximums and Deductibles

Our valuation assumes that all plan maximums and deductibles applicable to medical and dental plans remain the same in the future.

This assumption results in lower liabilities and expense than would result if the assumption were made that maximums and deductibles will increase in the future to maintain a constant sharing of costs between the employer and the plan members.

APPENDIX D

Summary of Plan Provisions

Grandfathered Plan Summary (Traditional Plan)

Eligibility

Employees who are eligible to retire under the terms of the pension plan (at age 55) are eligible for post-retirement benefits. Current retirees, surviving spouses, and employees with 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible to elect the traditional plan or the RHSA.

Spouses and dependants of retirees are eligible for health and dental coverage as well. Dental coverage ceases when the retiree reaches age 65.

On the retiree's death, health and dental coverage continues for the spouse and dependents. Dental coverage ceases when the surviving spouse reaches age 65, and there is no continuation of dental coverage if the surviving spouse is over age 65 when the retiree dies.

Cost Sharing

All costs for retiree benefits are employer paid.

Life Insurance

Group	Pre Age 65 coverage	Post Age 65 coverage
Non Union	2 x annual earnings at retirement	$5,000
Union	$40,000	$5,000
Part-Time	$15,000	$5,000

Medical and Dental Benefits

Hospital Benefits

Benefits cover 100% of semi-private room and board charges in excess of charges for ward accommodation and for ward-level user fees, where applicable. Hospital charges related to chronic case services are limited to a lifetime maximum of $10,000 per covered person.

Major Medical Benefits

Reimbursement Percentages

- 100% for paramedical practitioners and vision care expenses.
- 90% of first $1,000 of family's eligible expenses per calendar year and 100% of remaining eligible expenses.

Deductible

- None.

Maximum

- $50,000 per person in any three consecutive calendar years.

Eligible Expenses

- Prescription drugs.
- Ambulance services.
- Medical supplies and services (e.g. artificial limbs, orthopaedic shoes).
- Professional services.
- Services of a registered nurse, subject to a lifetime maximum of $5,000.
- Vision care ($100 per person for frames/lenses, $200 for contacts per person every 24 consecutive months).
- Hospital charges for emergency treatment outside Canada.

Provincial Benefits- Ontario Bill 26

Seniors age 65 and over in Ontario with sufficiently high income are required to pay the first $100 of annual drug costs followed by a $6.11 dispensing fee per prescription. The Plan reimburses retirees for these amounts.

Dental Benefits

Reimbursement Percentages

- 100% of basic expenses.
- 50% of major restorative expenses.
- 50% of orthodontic expenses.

Deductible

- None.

Fee Guide

Current Provincial Dental Association Fee Guide.

Dental Maximums

- $2,000 per person per calendar year for basic and major restorative expenses combined.
- $1,000 per person lifetime for orthodontic expenses.

Non-Grandfathered Plan Summary (Retiree Health Spending Account – RHSA)

Eligibility

Current retirees, surviving spouses, and employees that did not qualify by having 60 points (age plus service totals at least 60) as of 01 January 2004 for non-union employees and 01 January 2007 for union employees will be eligible for the RHSA plan if the employee has at least five years of employment when they retire.

On the retiree's death, the RHSA continues for dependants. Provincial health premiums also continue to be paid (50%).

Cost Sharing

With the exception of provincial health premiums, all costs for retiree benefits are employer paid.

Life Insurance

Life coverage will be $10,000.

Health Spending Account

The Company will provide a $1,500 per family health spending account allocation, from which the retiree will purchase catastrophic coverage as well as pay for out of pocket medical, dental and vision expenses. No indexation of this spending account is contemplated.

British Columbia Health Premiums

The Company will pay for British Columbia health premiums at 50% of the 2004 rates.

APPENDIX E

Employer Certification

With respect to the Report on Non-Pension Post Retirement Benefit Cost and Disclosure for the Fiscal Year Ending 31 December 2011 under CICA Section 3461 of the Enbridge Gas Distribution Inc.'s non-pension post retirement benefit plan, I hereby certify that, to the best of my knowledge and belief:

- The membership data supplied to the actuary provides a complete and accurate description of all persons who are entitled to benefits under the terms of the plan for service up to the date of the valuation, 01 January 2009;
- A copy of the plan documents and of all amendments made up to 31 December 2011 were supplied to the actuary;
- All substantive commitments have been communicated to the actuary;
- Accounting policies adopted by the Company are those described in this report;
- The actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- Management's best-estimate assumptions for purposes of the valuation of the Plan and the extrapolation of the financial position of the Plan as of the fiscal year end 31 December 2011 are those described in this report; and
- All events subsequent to the valuation that may have an impact on the results of the valuation have been communicated to the actuary.

February 13, 2012	February 14, 2012
Date	Date
Signed	Signed
John K. Whelan	SONIA HÉROUX
Name	Name
Sr. Vice President & Controller	SR MANAGER PENSION AND BENEFITS
Title	Title

APPENDIX F

Results by Participating Employer

REPORT ON NON-PENSION POST RETIREMENT BENEFIT COST AND DISCLOSURE FOR FISCAL 2011 UNDER CICA 3461

ENBRIDGE GAS DISTRIBUTION INC.

(all numbers in $000 Canadian)

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Beginning of Period 31 December 2010:				
Market Value of Assets	-	-	-	-
Accrued Post-Retirement Benefit Obligation (ABO)	80,425	1,299	961	82,685
Unamortized Net Transition Obligation	15,601	138	104	15,843
Unrecognized Prior Service Cost:	-	-	-	-
Unrecognized Experience Losses/(Gains):	(3,511)	398	151	(2,962)
Accrued Post Retirement Benefit Cost	68,335	763	706	69,804
EARSL to full eligibility	10.1	10.1	10.1	10.1
EARSL to decrement age	12.7	12.7	12.7	12.7
2011 Expense for Non-Pension Post Retirement Benefits:				
Employer Service Cost plus interest	1,236	30	55	1,321
Assumed rate to discount assets for period	0.00%	0.00%	0.00%	0.00%
Interest on Assets	0.00%	0.00%	0.00%	0.00%
Assumed rate to discount liabilities for period	5.70%	5.70%	5.70%	5.70%
Interest on Liabilities	4,489	73	54	4,616
Amortization:				
Net Transition Obligation	3,121	27	21	3,169
Prior Service Cost	-	-	-	-
Losses/(Gains)	-	-	-	-
Expense for Non-Pension Post Retirement Benefits	**8,846**	**130**	**130**	**9,106**
2011 Expected Benefit Payments:				
Benefit payments	(3,342)	(39)	(21)	(3,402)
> Cash	(3,342)	(39)	(21)	(3,402)
End of Period 31 December 2011:				
Expected Assets	-	-	-	-
Expected ABO	82,808	1,363	1,049	85,220
Plan Design Changes				-
				-
Market Value of Assets	-	-	-	-
Actual ABO	96,098	1,622	1,267	98,987
Discount rate for Disclosure	4.50%	4.50%	4.50%	4.50%
Unamortized Net Transition Obligation	12,480	111	83	12,674
Unrecognized Prior Service Cost:	-	-	-	-
Unrecognized Experience Losses/(Gains):	9,779	657	369	10,805
Accrued Post Retirement Benefit Cost	**73,839**	**854**	**815**	**75,508**

REPORT ON NON-PENSION POST RETIREMENT BENEFIT COST AND DISCLOSURE FOR FISCAL 2011 UNDER CICA 3461

ENBRIDGE GAS DISTRIBUTION INC.

	(all numbers in $000 Canadian)			
	Enbridge Gas Distribution Inc.	**Gazifere Inc.**	**Enbridge Gas New Brunswick Inc.**	**Total**
Projected Benefit Payments:				
2012	(3,527)	(40)	(23)	(3,590)
2013	(3,773)	(43)	(26)	(3,842)
2014	(4,042)	(45)	(30)	(4,117)
2015	(4,308)	(52)	(34)	(4,394)
2016	(4,586)	(58)	(34)	(4,678)
Next 5 Years	(25,952)	(358)	(246)	(26,556)
Sensitivity Disclosures:				
1. Effect of a 1% Increase in Medical Trend Rates				
Change in Year-End ABO	14,663	259	116	15,038
Change in fiscal Service Cost and Interest Cost	791	14	5	810
2. Effect of a 1% Decrease in Medical Trend Rates				
Change in Year-End ABO	(11,829)	(205)	(93)	(12,127)
Change in fiscal Service Cost and Interest Cost	(636)	(12)	(5)	(653)
3. Effect of a 0.5% Decrease in Discount Rate				
Change in Year-End ABO	7,351	147	125	7,623
Change in Expense	44	2	7	53
Trend Disclosures:				
1. Drugs				
Rate assumption for next fiscal year				8.40%
Ultimate trend rate assumption				4.50%
Ultimate trend rate assumption achieved				2029
2. Other Medical and Dental				
Rate assumption for next fiscal year				4.50%
Ultimate trend rate assumption				4.50%
Ultimate trend rate assumption achieved				2029
3. All Combined				
Rate assumption for next fiscal year				6.74%
Ultimate trend rate assumption				4.50%
Ultimate trend rate assumption achieved				2029

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Suite 900
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BOARD STAFF INTERROGATORY #14

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref(1): Ex. A2/Tab3/Sch 1/Appendix 4 Mercer Report, Updated Estimated 2013-2017 Cash Costs – EGD Non-Pension Post-Retirement Plans – 19 January 2012

Ref(2): Ex. A2/Tab3/Sch 1/Appendix 5 Mercer Report, Updated Estimated 2013-2017 Accrual Funding Costs – EGD Non-Pension Post-Retirement Plans – 19 January 2012

EGD updated its assumption of the discount rates for OPEB costs to 4.80% for the accrual basis of recording OPEB.

As per page 12 of Appendix 5, Mercer stated:

> The discount rate assumption has been updated from the rate used in the December 31, 2010 valuation to reflect market conditions as at October 31, 2011 and new CIA guidance released in September 2011.

Mercer did not disclose the discount used for the cash basis of recording OPEB costs in Appendix 4.

a) Please disclose the discount used for the cash basis of recording OPEB costs in Appendix 4.

b) Please provide the yield curve to show that the discounted rates used is supported by the yield curve of long term bonds. Please describe the yield curve used. Please explain.

c) Please provide the discount rate used in the December 31, 2011 valuation and the supporting documentation.

Witnesses: K. Culbert
S. Chhelavda

d) Please also demonstrate that the long term bonds selected by EGD covering a time period horizon approximate the period of EGD's future benefit payments for its OPEB plans.

e) Please explain why the discount rate used for the valuation on the accrual basis is 4.80% in Appendix 5 and is presumably different than that used on the cash basis in Appendix 4 as at December 31, 2011.

i) Please explain why two different rates are used as at December 31, 2011.
ii) Please reconcile the differences.
iii) Please explain the implications of these two different discount rates on the 2013 Test Year OPEB expense calculated on an accrual basis and the 2013 Test Year OPEB expense calculated on a cash basis.

RESPONSE

a) The OPEB costs on the cash basis disclosed in the Mercer Report represent expected future benefit payments in the year of reporting. They do not reflect present value of the payments and therefore are not dependent on a discount rate.

b) Please see response to part a) above.

c) The discount rate used in the December 31, 2011 accounting valuation report for valuing the OPEB funded status was 4.5%. Please refer to Attachment for a copy of the report.

d) EGD's OPEB plan is not pre-funded and is on a pay-as-you-go-basis. Therefore there are no long term bonds or any other type of investments selected as part of an asset pool used to fund future benefit payments.

e)
i. Please see response to part a) above.
ii. Please see response to part a) above.
iii. Please see response to part a) above.

Witnesses: K. Culbert
S. Chhelavda

03 February 2012

Enbridge Gas Distribution Inc.

Actuarial Valuation Report
Pension Expense and Employer Disclosure for the Fiscal Year Ending December 31, 2011 Under CICA Section 3461

MERCER

Consulting. Outsourcing. Investments.

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1

Report Highlights

Mercer has prepared this report to assist Enbridge Gas Distribution Inc. and its subsidiary companies (the "Company") and its auditors in preparing financial reports under Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461") relating to the following plans, known collectively as the Enbridge Gas Distribution Inc. Retirement Plans, for the fiscal year ending December 31, 2011:

- The Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "RPP");
- The Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "SERP"); and
- The Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP").

The RPP has a defined contribution component as well as a defined benefit component. The results presented in this report consider both components of the RPP. The RPP is funded by contributions from EGD unless it elects to use a funding excess to meet annual contribution requirements. Pension benefits payable from the defined benefit component are based on length of service and final average earnings and are partially indexed for inflation after retirement.

The SERP and the SSERP are closed plans, funded by contributions from EGD as necessary. Pension benefits are based on length of service and final average earnings and are partially indexed for inflation after retirement. There are no longer any active members in the SSERP.

Enbridge Gas Distribution Inc.'s fiscal year end date is December 31, and the measurement date for the plan assets and obligations as described in this report is December 31.

Employer contributions to the pension funds during the fiscal year ending December 31, 2011 were $567,800. These employer contributions were made in

accordance with the following reports effective December 31, 2010 (the "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, effective December 31, 2010;
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates, effective December 31, 2010; and,
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc., effective December 31, 2010.

The next actuarial valuation for funding purposes in respect of the RPP must be as of a date no later than December 31, 2012.

Changes in Plan Provisions

There were no changes in plan provisions since the last disclosure as of December 31, 2010.

Changes in Actuarial Cost Methods

There were no changes in actuarial cost methods since the last disclosure as of December 31, 2010.

However, there was a change in methodology for determining interest on the DB current service cost. Interest on the DB current service cost is now included in the current service cost itself (it was previously included in the interest cost).

This change in methodology only affects the allocation of costs between components, and has no impact on the net periodic pension cost or the accrued benefit obligation at year-end.

Changes in Asset Valuation Method

There were no changes in asset valuation method since the last disclosure as of December 31, 2010.

Changes in Assumptions

There were changes in actuarial assumptions since the last disclosure as of December 31, 2010. Please see the Summary of Assumptions in Appendix A of this report for a description of these changes.

Changes in Accounting Policies

There were no changes in accounting policies since the last disclosure as of December 31, 2010.

Transition to US Accounting Standards

Enbridge will be adopting US accounting standards on January 1, 2012. Due to the requirement to provide comparative information in the first set of financial statements, Enbridge has transitioned to US accounting standards from current Canadian GAAP as of January 1, 2011. On that date, a transition adjustment was made to retained earnings to bring the existing current CICA 3461 balances in line with the requirements of US accounting standards. Enbridge will continue to report under current Canadian GAAP in 2011. Two sets of financial results were maintained for 2011, one for current Canadian GAAP and another one for US accounting standards. In 2012, current Canadian GAAP will cease to exist and US accounting standards will commence with comparative information for 2011.

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Principal Expense and Disclosure Information

A summary of principal pension expense and disclosure information, as required for disclosure purposes pursuant to CICA 3461, from the current fiscal year and the prior fiscal year follows.

Components of Net Periodic Pension Cost	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Current service cost - DB	$16,710,900	$13,675,700
Current service cost - DC	1,345,400	1,717,500
Interest cost	38,937,100	38,390,500
Actual return on DB plan assets	(15,158,900)	(78,793,700)
Actuarial loss (gain) on accrued benefit obligation	125,704,600	80,807,600
Costs arising in the period	**$167,539,100**	**$55,797,600**
Differences between costs arising in the period and costs recognized in the period in respect of:		
▪ Return on plan assets	(37,767,700)	29,215,700
▪ Actuarial loss (gain)	(110,298,200)	(67,993,400)
▪ Past service cost	1,270,600	1,270,600
▪ Transitional obligation (asset)	(25,721,000)	(25,721,000)
Net periodic pension cost recognized	**($4,977,200)**	**($7,430,500)**

Weighted-Average Assumptions for Expense	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Discount rate	5.70%	6.60%
Expected long-term rate of return on plan assets	7.19%	7.18%
Rate of compensation increase	3.50%	3.50%

Weighted-Average Assumptions for Disclosure	December 31, 2011	December 31, 2010
Discount rate	4.50%	5.70%
Rate of compensation increase	3.50%	3.50%

Change in Accrued Benefit Obligation	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Accrued benefit obligation at end of prior year	**$699,580,700**	**$598,176,600[1]**
Current service cost - DB	16,710,900	13,675,700
Interest cost	38,937,100	38,390,500
Employee contributions	0	0
Benefits paid	(32,949,500)	(31,469,700)
Actuarial loss (gain)	125,704,600	80,807,600[2]
Accrued benefit obligation at end of year	**$847,983,800**	**$699,580,700**

Change in Plan Assets	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Fair value of plan assets at end of prior year	**$758,390,900**	**$711,836,200[3]**
Actual return on plan assets	15,158,900	78,793,700[4]
Employer contributions	567,800	948,200
Employee contributions	0	0
Benefits paid	(32,949,500)	(31,469,700)
DC contributions drawn from DB surplus	(1,345,400)	(1,717,500) [5]
Fair value of plan assets at end of year	**$739,822,700**	**$758,390,900**

[1] Based on September 30 measurement date.

[2] Includes a gain from change in measurement date of $22,204,300.

[3] Based on September 30 measurement date.

[4] Includes a gain from change in measurement date of $15,757,100

[5] Includes DC contributions from DB surplus between October 1, 2010 to December 31, 2010 of $319,300.

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Excess (deficit) at end of year	**($108,161,100)**	**$58,810,200**
Unamortized transitional obligation (asset)	(44,783,400)	(70,504,400)
Unamortized past service costs	2,470,600	3,741,200
Unamortized net actuarial loss (gain)	376,467,500	228,401,600
Accrued benefit asset (liability)	**$225,993,600**	**$220,448,600**

Weighted-Average Invested Plan Assets by Category	Fiscal Year Ending December 31, 2011	Fiscal Year Ending December 31, 2010
Equity securities	49%	52%
Debt securities	45%	41%
Other	6%	7%
Total	**100%**	**100%**

3

Certification

Mercer has prepared this report exclusively to assist Enbridge Gas Distribution Inc. and its subsidiary companies and auditors in preparing financial reports under Section 3461 of the Canadian Institute of Chartered Accountants Handbook relating to the Enbridge Gas Distribution Inc. Retirement Plans for the fiscal year ending December 31, 2011.

This valuation report may not be used or relied upon by any other party or for any other purpose. Mercer is not responsible for the consequences of any unauthorized use.

A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future.

Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, plan expenses and the amount earned on any assets invested to pay the benefits. These amounts and others are uncertain and unknowable at the valuation date, but are predicted to fall within a reasonable range of possibilities.

To prepare this report, *actuarial assumptions*, as described in Appendix A, are used to select a single scenario from the range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in mandated requirements, plan experience, changes in expectations about the future, and other factors. Due to the limited scope of the assignment, we did not perform, and thus do not present, an analysis of the potential range of future possibilities and scenarios.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related

issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

Actuarial Valuations and Extrapolations

We have prepared an actuarial valuation of the Enbridge Gas Distribution Inc. Retirement Plans' accrued benefit obligations for accounting purposes as at December 31, 2009 and extrapolated those results to December 31, 2010. The extrapolation of the accrued benefit obligations is based on assumptions as at December 31, 2010 and on actual cash flows for fiscal 2010. In accordance with our mandate, the purpose of this valuation and extrapolation is to account for the costs of the plan for the fiscal year beginning January 1, 2011 and ending December 31, 2011 in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook ("CICA 3461").

In addition, we have prepared a second actuarial valuation of the Enbridge Gas Distribution Inc. Retirement Plans' accrued benefit obligations for accounting purposes as at December 31, 2010 and extrapolated those results to December 31, 2011. The extrapolation of the accrued benefit obligations is based on assumptions as at December 31, 2011 and on actual cash flows for fiscal 2011. In accordance with our mandate, the purpose of this valuation and extrapolation is to enable Enbridge to satisfy year-end disclosure requirements under CICA 3461.

The financial positions of the plan and the determination of net periodic pension cost set out in this report are based on unaudited financial statements as of December 31, 2010 and December 31, 2011.

Plan Provisions

The results of the valuations set forth in this report reflect the contractual provisions of the plans as of the dates of the valuations and extrapolations as reported to us by Management.

The plans have not been amended since the last valuation and extrapolation for accounting purposes as at December 31, 2010. A summary of the plan provisions is provided in Appendix F of the following reports (the "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates, effective December 31, 2010;
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution and Affiliates, effective December 31, 2010; and,
- The Report on the Actuarial Valuation for Funding Purposes of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc., effective December 31, 2010.

Substantive Commitment

There was no substantive commitment as defined under CICA 3461 reported to us by Management.

Data

The valuations are based on the plan asset data presented in the unaudited trust statements prepared by CIBC Mellon for the period from January 1, 2010/ January 1, 2011 to December 31, 2010/December 31, 2011. The pension fund is held in trust by CIBC Mellon and is invested in accordance with the investment policy of Enbridge Gas Distribution Inc. Plan assets of the SERP and SSERP also include the refundable tax account held by the Canada Revenue Agency (the "CRA").

The plan asset data are summarized in the Principal Expense and Disclosure Information section of this report. We have tested the pensions paid and the lump-sum refunds for consistency with the membership data for the plan members who have received benefits. The results of these tests were satisfactory.

The valuations are also based on the membership data as at December 31, 2010 provided by Enbridge Gas Distribution Inc. The membership data, and the validation checks made on the data, are summarized in Appendix E of the Funding Reports.

Subsequent Events

After checking with representatives of Enbridge Gas Distribution Inc., to our knowledge there have been no events subsequent to December 31, 2011 which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

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

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions used in the valuations and determination of net periodic pension cost are summarized in this report.

4

Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of Section 3461 of the CICA Handbook.

The preparers of the financial statements have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best estimate assumptions, selected for accounting purposes, in accordance with Section 3461 of the CICA Handbook. We are not expressing any opinion on these assumptions.

In our opinion,

- The data on which the valuations are based are sufficient and reliable for the purposes of the valuations; and
- The calculations have been made in accordance with the requirements of Section 3461 of the CICA Handbook, reflecting application of Enbridge Gas Distribution Inc.'s accounting policies described in this report.

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

Respectfully submitted,

Allen Hornung
FSA, FCIA

03 February 2012

Date

Sarah Fitzmaurice
FSA, FCIA

03 February 2012

Date

Appendix A

Valuation Methods and Assumptions

This Appendix describes the methods and assumptions used to value the plan as well as the accounting policies used to calculate the net periodic pension cost.

Actuarial Cost Method

Accrued benefit obligations shown in this report are computed using the Projected Benefit Method Pro Rated on Services as defined in CICA 3461. The objective under this method is to expense each participant's benefits under the plan as they would accrue, taking into consideration future salary increases and the plan's benefit allocation formula. The accrued benefit is determined under this method as follows:

Under the Projected Benefit Method Pro Rated on Services an equal portion of the total estimated future benefit (i.e., with salary projection or cost escalation, where appropriate), is attributed to each year of service.

The accrued benefit obligation is the actuarial present value of the accrued benefit for valuation purposes at the beginning of the fiscal year and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

The plan's **current service cost** is the sum of the individual current service costs, and the plan's **accrued benefit obligation** is the sum of the individual accrued benefit obligations for all participants under the plan.

Method for Determining Market-Related Value of Plan Assets

The market value of plan assets has been used to determine the net periodic pension cost for the fiscal year ended December 31, 2011 and for disclosure purposes as at December 31, 2011.

Accounting Policies

Management applied the Recommendations of Section 3461 of the CICA Handbook prospectively and elected to amortize the transitional (asset)/obligation on a linear basis over the average remaining service of active members expected to receive benefits under the plan.

Future salary levels and inflation affect the amount of future pensions. The projected benefit method prorated on services has been used to determine the accrued benefit obligation and current service cost.

The expected return on plan assets is based on the fair value of plan assets.

Enbridge has elected to amortize past service costs resulting from plan amendments on a linear basis over the average remaining service period of active members expected to receive benefits under the plan.

Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation and the market-related value of plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan.

Enbridge Gas Distribution Inc.'s fiscal year-end date is December 31 and the measurement date of the plan's assets and obligations is December 31. The measurement date was changed from September 30 to December 31 in fiscal 2010. The impact of this change is included as an actuarial gain/loss in the period.

Obligations are attributed to the period beginning on the employee's date of joining the plan and ending on earlier of the date of termination, death or retirement.

Summary of Assumptions

The following assumptions were used in valuing the accrued benefit obligations under the plan and the employer's net periodic pension cost.

Measurement date	▪ September 30 for the 2010 expense determination ▪ December 31 for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Discount rate	▪ 6.60% per year for the 2010 expense determination ▪ 5.70% per year for the December 31, 2010 funded status and 2011 expense determination ▪ 4.50% per year for the December 31, 2011 funded status[6]
Long-term rate of return on invested assets	▪ 7.25% per year for the 2010 and 2011 expense determination
Increases in pensionable earnings	▪ 3.50% per year
Increases in the YMPE	▪ 2.50% per year for the 2010 expense determination ▪ 2.75% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Increases in maximum pension permitted under the *Income Tax Act*	▪ 2.50% per year for the 2010 expense determination ▪ 2.75% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Consumer Price Index	▪ 2.00% per year for the 2010 expense determination ▪ 2.25% per year for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Indexation of pensions in payment	▪ 1.10% per year in respect of Contributory service, 1.00% per year in respect of Non-Contributory and Senior Manager service for the 2010 expense determination ▪ 1.24% per year in respect of Contributory service, 1.13% per year in respect of Non-Contributory and Senior Manager service for the December 31, 2010 funded status, the 2011 expense determination and the December 31, 2011 funded status
Mortality	UP-1994 generational mortality table using scale AA
Disability	No allowance for future disabilities
Withdrawal	See tables of sample rates
Expenses	Implicit in long-term rate of return on assets
Retirement	See table of sample rates

[6] The discount rate as of December 31, 2011 was determined in accordance with the methodology proposed by the Canadian Institute of Actuaries in September 2011.

Percentage with spouse	80% married
Age difference	A male is assumed to be 2 years older than his spouse
Headcount	No allowance made for headcount growth

Sample rates from the age related tables are summarized below:

Age	Termination - Male	Termination - Female	Retirement
20	5.0%	9.5%	0.0%
25	5.0%	13.0%	0.0%
30	5.0%	11.0%	0.0%
35	4.6%	8.5%	0.0%
40	3.0%	4.0%	0.0%
45	2.5%	3.9%	0.0%
50	1.5%	2.8%	0.0%
55	0.0%	0.0%	5.0%
56	0.0%	0.0%	5.0%
57	0.0%	0.0%	7.5%
58	0.0%	0.0%	7.5%
59	0.0%	0.0%	10.0%
60	0.0%	0.0%	20.0%
61	0.0%	0.0%	20.0%
62	0.0%	0.0%	20.0%
63	0.0%	0.0%	20.0%
64	0.0%	0.0%	20.0%
65	0.0%	0.0%	100.0%

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

Appendix B

Results by Participating Employers

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 19 of 28

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

Decmeber 31, 2011 Measurement
Enbridge Gas Distribution Pension Plans - RPP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	663,169,500	10,461,100	7,007,900	680,638,500
Current service cost (employer)	15,754,900	376,600	579,400	16,710,900
Interest cost	36,917,700	588,200	391,800	37,897,700
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(30,845,700)	(352,900)	(348,200)	(31,546,800)
Net transfer in (out)	196,200	(160,800)	(35,400)	-
Actuarial loss (gain)	119,244,500	2,411,100	1,718,600	123,374,200
Benefit obligation - end	804,437,100	13,323,300	9,314,100	827,074,500
Change in plan assets				
Market value of plan assets - end of prior period	718,163,500	10,690,500	6,129,900	734,983,900
Actual return on plan assets	14,090,400	216,000	125,300	14,431,700
Employer contributions	-	-	-	-
Employee contributions	-	-	-	-
Benefits paid	(30,845,700)	(352,900)	(348,200)	(31,546,800)
DC contributions paid from DB surplus	(1,211,100)	(60,700)	(73,600)	(1,345,400)
Net transfer in (out)	170,500	(138,700)	(31,800)	-
Market value of plan assets - end	700,367,600	10,354,200	5,801,600	716,523,400
Reconciliation of funded status				
Funded status - surplus (deficit)	(104,069,500)	(2,969,100)	(3,512,500)	(110,551,100)
Unamortized transitional obligation (asset)	(41,889,000)	(399,400)	(204,000)	(42,492,400)
Unamortized past service costs	2,397,900	22,900	11,700	2,432,500
Unamortized net actuarial loss (gain)	361,078,000	5,338,200	2,991,000	369,407,200
Accrued benefit asset (liability)	217,517,400	1,992,600	(713,800)	218,796,200
Components of expense				
Current service cost (including provision for plan expenses)	15,754,900	376,600	579,400	16,710,900
Interest cost	36,917,700	588,200	391,800	37,897,700
Expected return on plan assets	(50,896,800)	(762,600)	(431,600)	(52,091,000)
Amortization of transitional obligation (asset)	(24,556,700)	(234,200)	(119,600)	(24,910,500)
Amortization of past service costs	1,202,200	11,500	5,900	1,219,600
Amortization of net actuarial loss (gain)	14,546,200	216,500	124,200	14,886,900
Net expense (income)	(7,032,500)	196,000	550,100	(6,286,400)
Current Service Cost - DC	1,211,100	60,700	73,600	1,345,400

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 20 of 28

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SERP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	13,033,200	-	-	13,033,200
Current service cost (employer)	-	-	-	-
Interest cost	718,400	-	-	718,400
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(909,600)	-	-	(909,600)
Net transfer in (out)	-	-	-	-
Actuarial loss (gain)	2,226,700	-	-	2,226,700
Benefit obligation - end	15,068,700	-	-	15,068,700
Change in plan assets				
Market value of plan assets - end of prior period	15,431,600	-	-	15,431,600
Actual return on plan assets	445,700	-	-	445,700
Employer contributions	567,800	-	-	567,800
Employee contributions	-	-	-	-
Benefits paid	(909,600)	-	-	(909,600)
Net transfer in (out)	-	-	-	-
Market value of plan assets - end	15,535,500	-	-	15,535,500
Reconciliation of funded status				
Funded status - surplus (deficit)	466,800	-	-	466,800
Employer contributions after measurement date	-	-	-	-
Unamortized transitional obligation (asset)	(390,200)	-	-	(390,200)
Unamortized past service costs	38,200	-	-	38,200
Unamortized net actuarial loss (gain)	5,366,800	-	-	5,366,800
Accrued benefit asset (liability)	5,481,600	-	-	5,481,600
Components of expense				
Current service cost (including provision for plan expenses)	-	-	-	-
Interest cost	718,400	-	-	718,400
Expected return on plan assets	(556,100)	-	-	(556,100)
Amortization of transitional obligation (asset)	(565,200)	-	-	(565,200)
Amortization of past service costs	51,000	-	-	51,000
Amortization of net actuarial loss (gain)	461,700	-	-	461,700
Net expense (income)	109,800	-	-	109,800
		-	-	
Composition of ending asset balance 12/31/2011				
Market value of RCA invested assets as per CIBC Mellon statement	7,951,500	-	-	7,951,500
Estimated value of Refundable Tax Account (RTA)	7,584,000	-	-	7,584,000
Market value of assets for disclosure	15,535,500	-	-	15,535,500

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 21 of 28

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SSERP

	Enbridge Gas Distribution Inc.	Gazifere Inc.	Enbridge Gas New Brunswick Inc.	Total
Change in benefit obligation				
Benefit obligation - end of prior period	5,909,000	-	-	5,909,000
Current service cost (employer)	-	-	-	-
Interest cost	321,000	-	-	321,000
Employee contributions	-	-	-	-
Plan amendments	-	-	-	-
Benefits paid	(493,100)	-	-	(493,100)
Net transfer in (out)	-	-	-	-
Actuarial loss (gain)	103,700	-	-	103,700
Benefit obligation - end	5,840,600	-	-	5,840,600
Change in plan assets				
Market value of plan assets - end of prior period	7,975,300	-	-	7,975,300
Actual return on plan assets	281,500	-	-	281,500
Employer contributions	-	-	-	-
Employee contributions	-	-	-	-
Benefits paid	(493,100)	-	-	(493,100)
Net transfer in (out)	-	-	-	-
Market value of plan assets - end	7,763,700	-	-	7,763,700
Reconciliation of funded status				
Funded status - surplus (deficit)	1,923,100	-	-	1,923,100
Employer contributions after measurement date	-	-	-	-
Unamortized transitional obligation (asset)	(1,900,800)	-	-	(1,900,800)
Unamortized past service costs	-	-	-	-
Unamortized net actuarial loss (gain)	1,693,500	-	-	1,693,500
Accrued benefit asset (liability)	1,715,800	-	-	1,715,800
Components of expense				
Current service cost (including provision for plan expenses)	-	-	-	-
Interest cost	321,000	-	-	321,000
Expected return on plan assets	(279,500)	-	-	(279,500)
Amortization of transitional obligation (asset)	(245,300)	-	-	(245,300)
Amortization of past service costs	-	-	-	-
Amortization of net actuarial loss (gain)	57,800	-	-	57,800
Net expense (income)	(146,000)	-	-	(146,000)
Composition of ending asset balance 12/31/2011				
Market value of RCA invested assets as per CIBC Mellon statement	2,715,400	-	-	2,715,400
Estimated value of EBP invested assets as per CIBC Mellon statement	2,541,900	-	-	2,541,900
Estimated value of Refundable Tax Account (RTA)	2,506,400	-	-	2,506,400
Market value of assets for disclosure	7,763,700	-	-	7,763,700

Appendix C

Additional Disclosures

Enbridge Gas Distribution

	2011				
	EGD RPP	EGD DC	EGD SERP	EGD SSERP	Total
Additional year-end information					
1. Sensitivity to key assumptions					
a. Half a percent decrease in expected return on assets					
i. Effect on pension expense	3,592,000	n/a	38,000	19,000	3,649,000
ii. Effect on year-end accrued benefit obligation	n/a	n/a	n/a	n/a	n/a
b. Half a percent decrease in discount rate					
i. Effect on pension expense	6,276,000	n/a	126,000	2,000	6,404,000
ii. Effect on year-end accrued benefit obligation	59,730,000	n/a	733,000	239,000	60,702,000
b. Half a percent decrease in rate of salary increase					
i. Effect on pension expense	(1,612,000)	n/a	(15,000)	-	(1,627,000)
ii. Effect on year-end accrued benefit obligation	(7,578,000)	n/a	(59,000)	-	(7,637,000)
2. Expected DB benefit payments					
31-Dec-2011 :					
31-Dec-2012 :	32,686,000	n/a	944,000	531,000	34,161,000
31-Dec-2013 :	33,993,000	n/a	982,000	552,000	35,527,000
31-Dec-2014 :	35,353,000	n/a	1,021,000	574,000	36,948,000
31-Dec-2015 :	36,767,000	n/a	1,062,000	597,000	38,426,000
31-Dec-2016 :	38,238,000	n/a	1,104,000	621,000	39,963,000
Next five years	215,397,000	n/a	6,220,000	3,500,000	225,117,000
3. Expected contributions in following year	16,952,000	1,497,000	677,000	-	19,126,000

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 23 of 28

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 24 of 28

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - RPP

Expected benefit payments				
31-Dec-2012 :	32,001,000			
31-Dec-2013 :	33,281,000			
31-Dec-2014 :	34,612,000			
31-Dec-2015 :	35,996,000			
31-Dec-2016 :	37,436,000			
Next five years	210,873,000			
Expected contributions				
31-Dec-2012 :	15,959,000	407,000	586,000	16,952,000
31-Dec-2013 :	33,169,000	685,000	783,000	34,637,000
31-Dec-2014 :	29,583,000	635,000	762,000	30,980,000
31-Dec-2015 :	26,697,000	596,000	750,000	28,043,000
31-Dec-2016 :	24,395,000	567,000	746,000	25,708,000
31-Dec-2017 :	22,586,000	545,000	746,000	23,878,000
31-Dec-2018 :	21,188,000	531,000	752,000	22,471,000
31-Dec-2019 :	17,271,000	441,000	634,000	18,344,000
31-Dec-2020 :	14,187,000	362,000	521,000	15,069,000
31-Dec-2021 :	14,689,000	375,000	540,000	15,603,000

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 25 of 28

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SERP

Expected benefit payments				
31-Dec-2012 :	944,000			
31-Dec-2013 :	982,000			
31-Dec-2014 :	1,021,000			
31-Dec-2015 :	1,062,000			
31-Dec-2016 :	1,104,000			
Next five years	6,220,000			
Expected contributions				
31-Dec-2012 :	677,000	-	-	677,000
31-Dec-2013 :	695,000	-	-	695,000
31-Dec-2014 :	176,000	-	-	176,000
31-Dec-2015 :	121,000	-	-	121,000
31-Dec-2016 :	77,000	-	-	77,000
31-Dec-2017 :	42,000	-	-	42,000
31-Dec-2018 :	14,000	-	-	14,000
31-Dec-2019 :	-	-	-	-
31-Dec-2020 :	-	-	-	-
31-Dec-2021 :	-	-	-	-

Filed: 2012-08-03, EB-2011-0354, Exhibit I, Issue D4, Schedule 1.14, Attachment 1, Page 26 of 28

Disclosure Information by Participating Employer for Fiscal Year Ending December 31, 2011

December 31, 2011 Measurement

Enbridge Gas Distribution Pension Plans - SSERP

Expected benefit payments				
31-Dec-2012 :	531,000			
31-Dec-2013 :	552,000			
31-Dec-2014 :	574,000			
31-Dec-2015 :	597,000			
31-Dec-2016 :	621,000			
Next five years	3,500,000			
Expected contributions				
31-Dec-2012 :	-	-	-	-
31-Dec-2013 :	-	-	-	-
31-Dec-2014 :	-	-	-	-
31-Dec-2015 :	-	-	-	-
31-Dec-2016 :	-	-	-	-
31-Dec-2017 :	-	-	-	-
31-Dec-2018 :	-	-	-	-
31-Dec-2019 :	-	-	-	-
31-Dec-2020 :	-	-	-	-
31-Dec-2021 :	-	-	-	-

Appendix D

Employer Certification

With respect to the Actuarial Valuation Report on Pension Expense and Employer Disclosure for the Fiscal Year Ending December 31, 2011 Under CICA Section 3461 of the Enbridge Gas Distribution Inc. Retirement Plans, I hereby certify that, to the best of my knowledge and belief:

- the membership data supplied to the actuary provide a complete and accurate description of all persons who are entitled to benefits under the terms of the plan for service up to the date of the valuation;
- a copy of the official plan documents and of all amendments made up to December 31, 2011 were supplied to the actuary;
- all substantive commitments (as defined under CICA 3461) have been communicated to the actuary;
- accounting policies as adopted by the company are those described in this report.
- the actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- the management best estimate assumptions for purposes of the valuations and the extrapolation of the financial position of the plan as of the fiscal year end December 31, 2011 are those described in this report; and
- all events subsequent to the valuation that may have an impact on the results of the valuation or of a future valuation have been communicated to the actuary.

February 13, 2012.
Date

J L Whelan.
Signed
John K. Whelan.
Name
Sr. Vice President & Controller
Title

Sonia Héroux
Signed
SONIA HEROUX
Name
SR. MANAGER PENSION AND BENEFITS
Title

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CME INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Reference: Exhibit A2, Tab 3 and its Appendices
Exhibit D1, Tab 3, Schedules 1 and 2
Exhibit M1, Tab 1, Schedule 4
Board Staff Interrogatory Nos. 84 to 97

By what extent does the 2013 revenue requirement decrease in a scenario where, for regulatory purposes, the cash basis of accounting for Pension Expenses continues.

RESPONSE

If the cash basis were to continue to 2013, the revenue requirement would increase as pension expense on a cash basis is higher than an accrual basis as evidenced in Exhibit A2, Tab 3, Schedule 2, Appendix A and B updated on 2012-06-08. The impact to revenue requirement would be an increase of approximately $1.8 million. Further if Enbridge were to remain on the cash basis beyond 2013 the increase to revenue requirement would be even greater as the delta between cash and accrual expense grows as evidenced in Exhibit A2, Tab 3, Schedule 2, Appendix A and B. The impact to revenue requirement for 2014-2017 would be an increase of approximately $13.6 million.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
S. Trozzi
B. Yuzwa

CME INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Reference: Exhibit A2, Tab 3 and its Appendices
Exhibit D1, Tab 3, Schedules 1 and 2
Exhibit M1, Tab 1, Schedule 4
Board Staff Interrogatory Nos. 84 to 97

By what extent, if at all, does the 2013 revenue requirement decrease if, for regulatory purposes, a switch to the accrual method for recovering Pension Expenses is approved commencing January 1, 2013, in the context of a Board finding that the transition to the accrual method ought to have been made by 2009?

RESPONSE

The 2013 revenue requirement would not change regardless of when Enbridge transitioned to the accrual method.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
S. Trozzi
B. Yuzwa

CME INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Reference: Exhibit A2, Tab 3 and its Appendices
Exhibit D1, Tab 3, Schedules 1 and 2
Exhibit M1, Tab 1, Schedule 4
Board Staff Interrogatory Nos. 84 to 97

Does EGD have the option of continuing to expense OPEB on a cash basis effective January 1, 2013? If so, then by what extent does the 2013 revenue requirement decrease in a scenario where, for regulatory purposes, the cash basis continues to apply to OPEB expense?

RESPONSE

Please see the response to Board Staff Interrogatory #10, part a), at Exhibit I, Issue D4, Schedule 1.10.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
S. Trozzi
B. Yuzwa

CME INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Reference: Exhibit A2, Tab 3 and its Appendices
Exhibit D1, Tab 3, Schedules 1 and 2
Exhibit M1, Tab 1, Schedule 4
Board Staff Interrogatory Nos. 84 to 97

By what extent, if at all, does the 2013 revenue requirement decrease if the switch to an accrual method for OPEB expense is approved commencing January 1, 2013, in the context of a finding that the transition to the accrual method should have been made by 2009?

RESPONSE

In 2009 Enbridge did transition to the accrual method for OPEB expense for financial accounting purposes. However, the 2013 revenue requirement would not change regardless of when the Company transitioned to the accrual method.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
S. Trozzi
B. Yuzwa

CME INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Reference: Exhibit A2, Tab 3 and its Appendices
Exhibit D1, Tab 3, Schedules 1 and 2
Exhibit M1, Tab 1, Schedule 4
Board Staff Interrogatory Nos. 84 to 97

Please produce copies of all documents, including email communications and presentations to EGD management, pertaining to the issue of switching from a cash basis to an accrual basis of accounting for Pension and OPEB expenses, for regulatory purposes, as of 2009, including the descriptions, if any, that were provided at that time of the possible impact of such transition on EGD's share of revenue sufficiencies then being realized under the auspices of the IRM Plan. In particular, what options were management asked to consider, at that time, and was the risk to EGD's share of over-earnings associated with a transition to accrual accounting for these items of expense in 2009 a factor that was identified in any of these documents.

RESPONSE

Enbridge did not complete a formal analysis on the issue of switching from cash to accrual for Pension and OPEB expenses for regulatory purposes as of 2009. Therefore, Enbridge is unable to produce copies of documents requested.

Witnesses: S. Chhelavda
K. Culbert
S. Kancharla
R. Lei
A. Patel
S. Trozzi
B. Yuzwa

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: A2/3/2, p. 3

Please advise the circumstances (e.g. market conditions, plan funding status, stage of the valuation cycle, etc.) in which the accrual basis is more volatile than the cash basis, and the circumstances in which the cash basis is more volatile than the accrual basis.

RESPONSE

Please refer to Exhibit A2, Tab 3, Schedule 2, updated 2012-06-01, on page 9 and 10 for a sensitivity analysis for both the accrual basis and cash basis. As shown in this exhibit the cash basis is more volatile compared to the accrual basis under both positive and negative asset and liability shocks.

Witnesses: S. Chhelvada
K. Culbert
S. Kancharla
A. Patel
B. Yuzwa

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 4: Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate, including the request to recover Pension Expense and Other Post-Employment Benefits ("OPEB") Expense on an accrual basis commencing January 1, 2013?

Ref: A2/3/2, p. 10

Please confirm that, as market conditions or discount rate assumptions or yield curve become more favourable, the cash basis will tend to produce lower annual costs relative to the accrual basis, and vice versa. If there is a formula or algorithm for estimating this effect, please provide.

RESPONSE

In general, the cash basis will produce lower costs than the accrual basis when asset and liability experience is favourable because gains on a cash basis can be realized immediately through contribution holidays while gains on an accrual basis are amortized over the expected average service life. However it then follows that, in general, the cash basis will produce higher costs than the accrual basis when asset and liability experience is not favourable because losses on a cash basis are amortized over five years while losses on an accrual basis are amortized over the expected average service life.

It should be noted that, regardless of changes in market conditions, discount rates or yield curves, at the end of the plan's life both cash and accrual basis costs will be the same.

Witnesses: K. Culbert
S. Chhelvada
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref(1): Ex D2/T1/S1/Appendix 2.3.1/p. 5
Ref(2): Ex D2/T1/S1/Appendix 9/p. 21-22 (MNP Report)

Enbridge stated at Ref(1) that, "the core design principle for the RCAM is the adoption of a service based approach for allocation as required by the OEB and the ARC", and later stated that, "Where a department supports more than one service and each service has a different causal relationship to affiliates, the services must be broken out so that the most appropriate allocation can be developed".

In the independent evaluation at Ref(2) performed by MNP, it was indicated that in 2007, service schedules were not amended to be more service specific and distinguish between activities that are EGD specific and common through all EI affiliates. Also, service refinement, another recommendation in 2007, was not followed.

Why has Enbridge chosen not to adopt these recommendations from the MNP report?

RESPONSE

The service schedules under the RCAM Inter-corporate Service Agreement already incorporate all EGD specific activities and those common EI activities from which EGD benefits in relation to each service. More specific information about how the allocations are performed is provided to EGD service recipients to inform their review of the service schedules. It is not necessary to include all supporting documents and calculations in the legal agreement between the parties. There is no apparent incremental benefit to re-state service schedules to include the additional data.

MNP's service refinement recommendation represents a fundamental departure from the RCAM developed by EGD in consultation with interested parties, and approved by the Board for the past five years. In response to pre-2007 concerns about lack of specificity of EGD's prior corporate cost allocation proposals, EGD developed service-

based allocations tailored to the specific corporate activities undertaken by EI. To attempt a re-categorization of services pursuant to the broad, general headings used in the Affiliate Relationships Code (e.g., legal, finance, risk management, audit services, etc.) would deviate from the specificity and transparency espoused in the RCAM. Further, EGD does not understand how such a re-categorization would be conducted reliably, and how it would be of benefit.

Neither the Board nor interested parties have urged EGD to adopt these MNP recommendations to date. EGD has therefore not pursued any further exploration of the related costs and benefits. As noted in Exhibit D1, Tab 4, Schedule 2, paragraph 17, EGD is prepared to reconsider MNP's updated recommendations going forward, subject to further review, the Board's requirements and discussions with interested parties.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: D2/T1/S1/Appendix/pp36, 37, 48

Three RCAM primary service costs fell above the MNP fair market value range of internal service provision costs and failed the Prong Three Test. Page 48 of the MNP report states that "MNP has recommended a combined downward adjustment to the 2012 RCAM allocations of $154,923…MNP recommends a corresponding combined downward adjustment to the 2013 RCAM allocations of $158,329."

Will recommendations set forth by MNP for 2013 be followed by Enbridge in the future (to decrease RCAM allocations of $154,923 in 2012 and $158,329 in 2013)?

RESPONSE

As noted at Exhibit D1, Tab 4, Schedule 2, page 4, paragraph 14, the Company has accepted MNP's proposed RCAM amount of $31.6 million for 2012 for the purpose of determining the 2012 earnings sharing mechanism.

The Company has also accepted and incorporated the 2013 RCAM cost adjustments proposed in the MNP study for rate making purposes, which is confirmed in evidence at Exhibit D1, Tab 4, Schedule 2, page 4, paragraph 14. In doing so, the Company has incorporated MNP's proposed total 2013 RCAM amount of $32.1 million, identified in Exhibit D2, Tab 1, Schedule 1, page 51, into the updated revenue requirement presented in the Impact Statement (Exhibit M1, Schedules 1 to 5). The RCAM update is specifically identified as one component of the operation and maintenance adjustment included in Exhibit M1, Tab 1, Schedule 4, pages 1 and 2, Line 9. The RCAM amount included in utility operation and maintenance costs was increased by $1.8 million, which is the delta between MNP's proposed $32.1 million and the $30.3 million RCAM placeholder amount included in the Company's pre-filed evidence.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: D1/T4/S2/Attachment 1/pp33, 46

FCER (Financing Capital Employed Ratio) and ACER (Adjusted Capital Employed Ratio) are calculated based on the Capital Employed without the Purchase Premium. Attachment 1 also indicates that the ACER is currently 15.75% and FCER is 13.87%.

Does Enbridge's Capital Employed include the value of all the assets employed in a business, including equity and preference share capital, fixed and current assets, and gross borrowings plus current assets and less current liabilities? What else makes up this amount?

Does ACER remain consistent at 15.75% for all services with an ACER allocator, and does FCER remain consistent at 13.87% for all services with a FCER allocator?

Please provide a chart of how ACER and FCER allocation percentages have changed over the last 10 years.

RESPONSE

This confirms that the Enbridge's Capital Employed includes everything that is captured in its balance sheet under the categories of assets and liabilities, including all the assets employed in a business, including equity and preference share capital, fixed and current assets, and gross borrowings plus current assets and less current liabilities.
Over the years, ACER and FCER have been consistently applied across all services under the RCAM. For the relevant years 2011 to 2013, ACER and FCER have been consistently applied for all services at 15.75% and 13.87% respectively.

ACER and FCER values are presented from 2006 onwards recognizing that the RCAM was first introduced in 2006.

Witnesses: B. Yuzwa
S. Chhelavda

ACER and FCER Chart 2006-2013

	2006	2007	2008	2009	2010	2011-3
FCER	20%	19.81%	19.33%	17.73%	15.49%	13.87%
ACER	26%	24.85%	24.27%	21.72%	17.04%	15.75%

As shown above, ACER and FCER percentages have declined over the years.

Witnesses: B. Yuzwa
S. Chhelavda

BOARD STAFF INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref(1): D2/T1/S1/Appendix/pp39-42,
Ref(2): D1/T4/S2/Attachment 2

IT and HR costs contribute to 74% of the overall increase in Primary Services, totalling $5.4 million. MNP found it difficult to benchmark this figure for comparable entities over similar periods of time for HR and IT. The increase is claimed to be due to increased support requirements such as "Multi-year Financial Renewal project, Financial reporting requirements, Khalix upgrades, expense report system enhancements, HRCore Project, enterprise content management enhancements, SharePoint upgrade, Microsoft upgrades, and program and project management for upgrades."

According to Ref(2), there was a $478,825, or 122% increase in Enterprise IT Program Management costs as a RCAM allocation from 2011 to 2012.

Why was there a 122% increase in Enterprise IT Program Management costs? Please provide a list of breakdown of IT expenses that contribute to each of the system implementations and enhancements as outlined, and explain how they contribute to the large increase to the Enterprise IT Program Management and other Information Technology categorized primary services and add value and future efficiencies to the operations of Enbridge Gas Distribution.

RESPONSE

The increase in the Enterprise IT Program Management Service costs was driven by the above named enterprise-wide projects. The above named projects have been undertaken to replace outdated technologies in Finance, HR and other areas within the Company. Some of the benefits of these projects include reduction in administrative burden through the simplification of existing complexities, improved data consistency to provide better decision support, improved costing and reporting accuracy, and faster turnaround times for data processing.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

BOARD STAFF INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: D2/T1/S1/Plus Appendix/p. 42

According to EGD, 18% of its workforce is eligible to retire today, and 30% can retire within the next 5 years. This relates to the higher HR costs required for succession planning.

What age, or years of service, does Enbridge use for the purpose of determining employees that are 'eligible' for the purposes of retirement?

Historically, over the past 5 years, what percentage of EGD's workforce retires every year?

How many new FTEs does EGD expect to hire in each year over the next 5 years? Please provide any forecasts created and/or presented to management on this issue, or provide an appropriate reference to the evidence already filed in the current proceeding where these forecasts are made available.

RESPONSE

For retirement purposes, Enbridge uses one of the following factors in determining retirement eligibility:

Age 60 or
Age 55 plus 30 years of service

The table below represents the annual percentage of EGD's active employees that have retired. However the percentage of employees that are eligible to retire is significantly higher.

Year 2007	2008	2009	2010	2011
2.3%	3.3%	3.4%	3.6%	1.6%

Witnesses: S. Chhelavda
L. Liauw
S. Trozzi
B. Yuzwa

Gross new FTE's expected to be hired:

Year 2012	2013
161	56

Detailed budgets for the periods post 2013 have not been developed at this time.

Witnesses: S. Chhelavda
L. Liauw
S. Trozzi
B. Yuzwa

BOARD STAFF INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: D2/T1/S1/Plus Appendix/p43

What is "HRIS and PeopleSoft optimization"?
Can Enbridge clarify the costs and benefits involved with these above noted new HR initiatives?

RESPONSE

HRIS stands for Human Resources Information Systems and it supports the optimization of organizational capability by maintaining reliable and cost-effective Human Resources systems, principally PeopleSoft, through the standardization, simplification, and optimization of Human Resources business processes through innovation and leading practices.

PeopleSoft optimization involved costs of upgrades to software, databases and platforms.

Current Situation:

- Losing support for current platform (PeopleTools 8.46 and PeopleSoft HCM 8.9) commencing in December 2010.
- Oracle 10g database is at the end of life and went into extended support in July of 2010. This database needs to be upgraded to Oracle 11g but cannot be done without upgrading PeopleTools (11g is not certified on PeopleTools 8.46). HR cannot maintain levels of service and system cannot continue to be "patched".
- HR is in the process of implementing many initiatives to harmonize or standardize HR processes and data with a view to improving operational efficiencies. In doing so, HR is looking to adopt leading practices and effective tools capable of delivering those practices. PeopleSoft HCM 9.1 provides improved functionality for Talent Management (Recruiting, e-Performance, Succession Planning, Career Planning), Compensation Management, Self-

Service, Payroll and Human Resources. These improvements will not be addressed during the upgrade but will form the foundation upon which the harmonization efforts can be built.

- IT and HR have made significant investments (financial, people resources, processes/ guidelines) into PeopleSoft as the 'Enterprise' HRIS platform. If this platform is not upgraded, it runs the risk of becoming an out-dated and less attractive business support system, leaving the user base to find alternative systems.

Benefits of PeopleSoft Optimization:

- Mitigates the risk of software and database failure by upgrading to current software and database versions that will be supported by vendors
- Introduces a stronger platform from which to address key functional limitations to critical talent management processes such as recruiting, compensation and performance management.
- Reduces technical support costs through the elimination of over 82% of the customizations currently in the PeopleSoft HCM 8.9 application.
- Enables the further elimination of customizations in future phases which will further reduce the technical support costs.

Witnesses: S. Chhelavda
S. Trozzi
B. Yuzwa

BOARD STAFF INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref(1): A2/T1/S1/p13/para48
Ref(2): D1/T4/S2/Attachment 2

According to Ref(1) of the Introductory Evidence submitted by Enbridge, "Another cost pressure comes from the Company's insurance costs, which have increased by approximately 67% since 2007." Based on the Enbridge RCAM Allocation Trend – 2007 To 2013 chart provided at Ref(2), insurance premiums have increased by $4,145,190, or 95.54% from 2011 to 2012. It has increased by $3,578,567.90, or 72.95% since 2007.

Please provide a derivation of how was the 67% increase calculated?
What components attribute to the increase in direct insurance premiums over the 2011 to 2012 year?

RESPONSE

With respect to Ref (1), "Another cost pressure comes from the Company's insurance costs, which have increased by approximately 67% since 2007.", the calculation of the 67% increase in insurance premium costs is as follows:

2007	$4,905,300
2012	$8,199,552
Increase	$3,294,252 or 67.2%

The $8,199,552 represents an earlier estimate for insurance premium costs at the time of the preparation of the introductory evidence in January 2012 that later revised to $8,483,868.

With respect to cited increase in insurance premium costs from 2011 to 2012, it should be noted that the Company's approved allocation of $4,338,678 for the 2011 under the

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

Inter-corporate Service Agreement did not reflect the actual amount incurred ($7,156,860). Therefore, the true increase from 2011 to 2012 is $1,327,008, or 18.54%.

The increase in insurance premium costs in 2012 relative to the prior year reflects a budget recognition of expected premiums incorporating actual amounts incurred in 2011. The primary driver remains to be the continuing effects of the Company's loss experience in 2010.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

BOARD STAFF INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref(1): D2/T1/S1/ Plus Appendix/p46
Ref(2): D1/T4/S2/Attachment 2

According to Ref(1) of the independent report submitted by Enbridge, Enterprise Content Management experienced a 1000% increase since 2007 (from $523,784 to $5,821,798), and the EGD RCAM % of EI Department Budget decreased by 37%.

What accounted for the 1000% increase in costs for Enterprise Content Management? If this was due to a reallocation of staff or other resources across different department, please explain.

RESPONSE

Records are important in safely delivering energy to our customers. The need for a more robust and comprehensive records and information management program is a direct result of the increasingly complex and burdensome governance and compliance environment in which Enbridge Gas Distribution operates. There are also increased requirements for Records Management governance including chain of custody requirements and auditable, verifiable and traceable critical records to meet current business governance and control best practices.

The IT system used by Enbridge for documents and records is the Livelink Enterprise Content Management System. Significant investment has been made since 2010 to upgrade IT applications and generally to improve services for access to and to secure storage of operational and critical information, including legacy records systems.

The Livelink system is to support Enbridge's commitment to emerging regulatory changes for pipeline operators – especially those around auditable, traceable and verifiable records. Livelink is now becoming Mission Critical at Enbridge and as such there are costs/implications for the increased availability, support and host site

Witnesses: B. Yuzwa
S. Chhelavda

capability. Additional enterprise tools and services include EnCase which supports discovery requests, audits and record searches.

Witnesses: B. Yuzwa
S. Chhelavda

BOARD STAFF INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: D2/T1/S1/Appendix/p46

Preamble: Although the EGD RCAM % of EI Dept Budget Allocation has generally decreased from 2007, the absolute values of costs have increased substantially for many departments of EI.

What accounted for the increase in costs for the following departments?

- Corporate HR
- EPI Charge
- IT Planning and Governance
- Organizational Effectiveness

RESPONSE

EGD's RCAM % of EI Department Budget Allocation has decreased from 2007, however EI department budgets have increased.

- The increase in the Corporate HR department budget from the 2007 level was driven by organizational structure changes resulting from the centralization of the HR functions across the enterprise.

- The increase in the EPI Charge department budget since 2007 mostly reflects the continued enhancements and upgrades to the IT infrastructure, as well as increased hardware and application support due to business growth across the enterprise.

- The increase in the IT Planning and Governance department budget since 2007 has been driven by the increased support requirements associated with the various enterprise-wide projects referred to on page 41 of the MNP report dated May 17, 2012.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

- The Organizational Effectiveness department budget increases over the years reflect the continued higher level of support related to the enhanced leadership development program, including the Knightsbridge Executive Development Program, re-launch of the Mentoring Program, redesign of the Change Management Program, and the new union performance management process.

BOMA INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: Exhibit D1, Tab 4, Schedule 2, Attachment 2, Page 10 of 10.

Please compare the Enbridge RCAM trend from 2007 to 2013 with the trend of total O&M expenditures of Enbridge Gas Distribution, exclusive of the allocation amounts.

RESPONSE

($Millions)

	2007	2008	2009	2010	2011	2012		2013	
RCAM	18.1	19.1	21.1	24.3	26.7	31.6	*	32.1	*
O&M, net of RCAM	303.9	304.3	315.9	322.4	333.8	370.6	**	406.0	***

*RCAM amounts per MNP's recommendations contained in its final report dated May 17, 2012 which the Company has accepted.

** Estimate

*** Budget

Witnesses: B. Yuzwa
S. Chhelavda

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: D1/T4/S2/p. 2

At a high level please explain how the RCAM amount has gone from $18.1 million in 2007 to $32.1 million in 2013.

RESPONSE

Please refer to Exhibit D1, Tab 4, Schedule 2, Attachment 2, filed June 1, 2012 for a schedule that provides a high level review of the numeric increase of the RCAM amount from 2007 to 2013.

The largest components of the increase in the RCAM amount in 2013 versus 2007 are:

- Stock based compensation;
- Insurance Premiums;
- HRIS Management & Technical Support;
- Employee Development; and
- Total Compensation and Benefits

Which are partially offset as a result of:

- an increased Direct EFS Charge (credit); and
- the exclusion of Audit Fees which are now charged directly to EGD.

Witnesses: S. Chhelavda
K. Culbert
B. Yuzwa

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Ref: Exhibit D1, Tab 24, Schedule 1

Please update the table on page 1 with the final numbers referred to in the footnote to the table.

RESPONSE

Please refer to Exhibit D1, Tab 24, Schedule 2, page 1, filed on May 31, 2012.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Reference: Exhibit D1 Tab 4 Schedule 1 Paragraphs 14-16

a) Please provide an extract of the Settlement Agreement(s) pertaining to RCAM together with source references.

b) Please provide a copy of the annual reports provided to the RCAM consultative during the IRM period (Appendices may be omitted).

c) Please confirm that the primary purpose of the consultative was to inform intervenors about changes to RCAM allocations that exceeded the thresholds in the Settlement Agreements;

d) Please confirm that the amounts included in the annual reports as payments to Enbridge Inc under RCAM were not endorsed by the consultative, and

e) Please confirm that the difference between the reported amounts and the amounts allowed in rates was eliminated by EGD when calculating the IRM Distribution Revenue Requirements.

RESPONSE

a) Please see Attachment 1. Source: Appendix A to Decision with Reasons EB-2006-0034 May 20, 2008.

b) Please see Attachments 2.1 to 2.5

c) Yes, that and the presentation of all of the underlying material and information utilized in the development of the annual RCAM amount.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

The information provided by the Company to the consultative group members in the annual reports was done on a without prejudice basis in accordance with the RCAM Supplementary Settlement Proposal dated September 27, 2007. As well, the information was provided on a confidential basis as if such information had been provided by the Company during a Settlement Conference.

For 2008 to 2010, the RCAM amounts included in the annual reports that were shared with the Intervenors through the consultative processes have been accepted by the Board for earnings sharing purposes. While the mechanics of the earnings sharing calculations have been agreed to for 2011 and 2012, the 2011 ESM proceeding is currently being processed by the Board.

d) Payments to Enbridge Inc have been made under (based on) CAM, not RCAM.

e) The Company confirms that the difference between CAM payments and RCAM amounts approved under the Inter-corporate Service Agreement, have been eliminated by Enbridge when calculating the IRM Distribution Revenue Requirements.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

SUPPLEMENTARY SETTLEMENT PROPOSAL

REGULATORY COST ALLOCATION METHODOLOGY

September 27, 2007

3.6 Do the revisions to the Regulatory Cost Allocation Methodology (RCAM) meet the Board's directives in the 2006 decision?

(Incomplete Settlement)

The issue of whether the revisions to RCAM meet the Board's directives from the 2006 decision has been a subject of the corporate cost allocation consultative which has been ongoing. As set out below, parties have been able to come to an agreement to settle certain issues relating to the RCAM.

All aspects of this Supplementary Settlement Proposal are subject to approval by the Board. The parties to the settlement all agree that this Supplementary Settlement Proposal is a package: the individual aspects of this agreement are inextricably linked to one another and none of the parts of this settlement are severable. As such, there is no agreement among the parties to settle any aspect of the issues addressed in this Supplementary Settlement Proposal in isolation from the balance of the issues addressed herein. The parties agree, therefore, that in the event that the Board does not accept this Supplementary Settlement Proposal in its entirety, then (in accordance with the Board's Settlement Conference Guidelines) the Board will reject the Supplementary Settlement Proposal in its entirety and proceed to hearing.

This Supplementary Settlement Proposal, if approved by the Board, will be added to the Settlement Proposal (Ex. N1-1-1) approved by the Board on January 29, 2007 (the "January 29th Settlement Proposal") and the provisions of this Supplementary Settlement Proposal will supersede the references at pages 26 and 27 of the January 29th Settlement Proposal which state that there is no settlement of Issue 3.6. As the January 29th Settlement Proposal settled the level of the Company's O & M Budget for 2007, this Supplementary Settlement Proposal, if approved by the Board, will have no impact on the Company's revenue requirement for 2007.

With that preamble, the following represents the settlement that has been agreed upon.

The Parties agree and accept that, subject to the requirements and exceptions set out below, the Company has complied with the Board's directives from the 2006 decision in respect of its RCAM.

Parties agree that the corporate cost allocation consultative will be continued. Commencing in 2008 and for each year that the Company operates under an incentive rate regulation regime, the Parties agree that where the thresholds set out below are exceeded, the Company will, on an annual basis, provide to members of the consultative the following information:

(i) a summary table setting out the direct and common allocation costs allocated to the Company for each service and all direct charges allocated to the Company for the year in question and the total allocation costs for

each service and direct charge for the immediately preceding year. In addition, the Company will provide the consultative with a table setting out the departmental O & M budgets for Enbridge Inc. for the year in question;

(ii) the Company will give the consultative notice of any service which is discontinued in its entirety. The Company will also provide the consultative with a copy of the service schedule for any new service or direct charge which is undertaken or incurred in 2008 and beyond. The Company will also provide the consultative with notice of its implementation of any of the recommendations made by Meyers Norris Penny LLP in its report dated February 28, 2007.

Furthermore, where the thresholds set out below are exceeded, the Company shall provide the following additional information:

(i) description of the drivers for increases in RCAM costs which exceed the aggregate threshold;

(ii) where the threshold for an individual service or direct charge is exceeded, the Company will provide to the consultative a description of the drivers for the increase and a copy of the most current service schedule for the service/charge in question.

Parties agree that the thresholds which trigger the above obligations are as follows:

(1) The aggregate corporate cost allocation amount for 2007 rates is $18.1 million. Should this amount increase in 2008 by an amount greater than the Ontario Consumer Price Index ("CPI") plus 3%, the aggregate threshold has been triggered. For subsequent years, the aggregate threshold is triggered where the increase in the aggregate of all RCAM allocations to the Company in comparison to the immediately preceding year is greater than the CPI plus 3%.

(2) The individual service threshold is triggered where the corporate cost allocation to any specific service or any direct charge increases in any one year by an amount greater than the CPI plus 10% and the increase is greater than $50,000.

The parties agree that the thresholds set out above are to be interpreted only as triggering mechanisms in respect of the reporting requirements set out herein and are not necessarily indicative of the parties' views regarding reasonable year over year changes in RCAM amounts payable by EGD.

The Company agrees that it will entertain and respond to any reasonable questions received from the consultative in relation to the information it provides to the

consultative as required above. Parties agree that all responses and all information provided to the consultative which it may then share with other intervenors will be on a without prejudice basis and will be treated as if such responses and information had been provided by the Company during a Settlement Conference.

Parties agree that this Supplementary Settlement Proposal in no way infringes upon any existing or future rights that any party may have under the Act or in any future proceeding.

Parties have not settled issues in respect of the following service and Direct charge, but have been able to scope the remaining issues for the purposes of the hearing, as follows:

Capital Market Financing and Access

Are the costs related to obtaining and maintaining equity capital by Enbridge Inc. appropriately recoverable from ratepayers through the RCAM?

EGD Stock Based Compensation

Are stock option expenses appropriately recoverable from ratepayers through the RCAM? (Performance stock units are not in issue)

Participating Parties: All parties participated in the negotiation and settlement of this issue except: ABSU, Coral, Direct Energy, Gazifere Inc., GEC, HVAC Coalition, Networks, Jason Stacey, LIEN, OAPPA, OESLP, OPG, Pollution Probe, Sithe Goreway, SEM, Thomas Matz, TransAlta, TransCanada Energy Ltd., TransCanada, Union Energy LP, and Union.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

A1-9-1	List of Affiliate Transactions
D1-2-2	Employee Expenses and Workforce Demographics
D1-2-3	Supplementary Evidence RCAM: Stock Option Compensation
D1-3-1	Corporate Cost Allocations
D1-3-2	RCAM: Update and Summary of Independent Evaluation, and Intercorporate Services Agreement
D2-1-1	Corporate Cost Allocation: Meyers Norris Penny LLP Report, February 28, 2007, and Appendices
D2-1-2	MNP Reply to Preliminary Report of Rosen and Associates, September 14, 2007
D3-2-3	Operating and Maintenance Expense by Cost Type
I-1-27 to 28	Board Staff Interrogatories 27 and 28
I-9-1	IGUA Interrogatory 1

I-16-38 to 39, 57	SEC Interrogatories 38, 39 and 57
I-24-2 to 3, 34 to 37	VECC Interrogatories 2, 3 and 34 to 37
KT11.1-1 to 2	Board Staff Interrogatories 1 and 2
KT11.2-1 to 19	VECC Interrogatories 1 to 19
L-28-1	Preliminary Report of Rosen & Associates Limited, May 30, 2007
Tr.	Transcript of Technical Conference, May 1, 2007
JTII.1, 1-10	EGD Undertaking Responses, 1 to 10
KTII.3,1 to 6	EGD Interrogatories 1 to 6

Regulatory Cost Allocation Methodology (RCAM) - UPDATE REPORT FOR 2008

(October 7, 2008)

Introduction:

One of the issues in the 2007 rate case[1] was issue 3.6: Does the revised RCAM conform to the Board's directives in the EB-2005-0001 Decision?

The OEB issued a procedural order indicating that this matter would be considered as a second phase of EGD's 2007 rate application hearing.

In the first phase of the hearing the Board accepted, as part of the "completely settled package", the parties' agreement on issue 3.7 which was the quantum of the RCAM allocation for 2007 ($18.1 million). A supplementary Settlement Agreement was filed with the Board on September 26th, 2007 and presented to the Board at an oral hearing on September 27th, 2007. The Board accepted the Supplemental Agreement during the hearing. The parties[2] were able to reach an agreement on all outstanding issues with respect to the RCAM except the cost of raising equity and the cost of stock options. The OEB's Decision with Reasons dated May 20, 2008 dealt with those two issues.

As per the terms of the supplementary Settlement Agreement, commencing in 2008 and for each year that the Company operates under an incentive rate regulation regime, EGD had agreed to provide certain information to the intervenors in the event that certain thresholds, as defined in the subject agreement, were triggered.

2008 RCAM Report:

Given the thresholds set out in the RCAM Supplementary Settlement Agreement dated September 27, 2007 (RCAM Agreement) are exceeded, this report represents the initial report made pursuant to the RCAM Agreement. A copy of the RCAM Supplementary Settlement Proposal, dated September 27, 2007, is attached for the reader's ready reference.

The information contained in this report has been prepared in accordance with the terms and conditions of the subject agreement and is being provided to members of the RCAM consultation group. It is understood that all responses and all information provided to the consultative may be shared with other intervenors. However, it is further understood that all information so provided will

[1] Board File No. EB-2006-0034
[2] Intervenors: Consumers Council of Canada, Energy Probe Research Foundation, Industrial Gas Users Association, School Energy Coalition and Vulnerable Energy Consumers Coalition.

be on a without prejudice basis and will be treated as if such responses and information had been provided by the Company during a Settlement Conference.

The 2008 information package consists of this report and the following accompanying documents:

Attachment	Document Description
1	A summary table setting out the direct and common allocation costs allocated to the Company for each service and all direct charges allocated to the Company for the year 2008 and the total allocation costs for each service and direct charge for the year 2007
1(a)	A schedule providing details of the 2008[3] costs for each service, including EI's total loaded departmental cost, the total amount allocated to the primary service, the direct and common allocations to EGD and the direct and common allocations to other affiliates (Source: Appendix A to Schedule 2(c), the signed 2008 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)
1(b)	Four (4) accompanying schedules to Attachment 1(a) providing further details on 2008 costs: Primary Service Costs; General Expenses and Direct Charges; Return on Invested Capital Calculation; and EI's Support Services Cost (Source: Accompanying Schedules to Appendix A to Schedule 2(c), the signed 2008 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)[4]
2	A table setting out the departmental O & M budgets for Enbridge Inc. for the year 2008
3	2008 versus 2007 RCAM Allocations Variance Analysis
4	A copy of the most current service schedule for those individual services/charges where the threshold for an individual service or direct charge has been exceeded

Background Information:

- There have been no changes in methodology since the 2007 rate case.

- Enbridge Inc.'s RCAM departmental budgets increased by $5.1 million or 3.6% to $145.2 million in 2008 from $140.1 million in 2007:

[3] The corresponding information for 2007 can be found at Exhibit D1, Tab 3, Schedule 2, Attachment 2, page 37 of 148 filed in EB-2006-0034
[4] The corresponding information for 2007 can be found at Exhibit D1, Tab 3, Schedule 2, Attachment 2, pages 38-49 of 148 filed in EB-2006-0034

- For 2008[5], all budgeted costs, except for the Gas Fundamental Department (a component of the Gas Supply, Storage, and Transportation Strategy service), were based on Enbridge Inc.'s 2007 departmental budgets inflated by 3.73%[6]. For the Gas Fundamental Department, an estimate of the 2008 departmental budget was used because the department did not exist in 2007.

- The aggregate threshold for 2008 in respect of RCAM cost allocations to EGD is 5%[7].

- The individual service threshold for 2008 is 12% and greater than $50,000.[8]

- There is typically a lag in RCAM recognition of changes in EI's budgeted costs from year to year having regard to the inherent time conflict between EGD's regulatory compliance cycle and EI's budgeting cycle. For any given year, the RCAM budget, which is based on EI's departmental budgets for the previous year as adjusted for inflation, is developed well in advance of the availability of EI's actual departmental budgets for the year in question.
  - This occurs because of the need for EGD to adhere to the Annual Review Process timelines specified in the ISA and to meet its regulatory compliance requirements
  - This can result in material changes in RCAM allocations for individual services and direct charges year over year
  - As an example, this has contributed significantly to the material increases in RCAM allocations in 2008 self-evident for SBC, Audit Fees and Records and Information Management Service

Aggregate Threshold:

- The aggregate corporate cost allocation amount for 2007 rates was $18.1 million. This amount has increased in 2008 by $1.0 million or 5.6% to $19.1 million. Thus, the aggregate threshold of 5% for 2008 has been triggered.

- The drivers for increases in the RCAM cost allocations which exceed the aggregate threshold are as follows:
  - A combination of a material net increase in Total Direct Charges and a minor net increase in Total Service Charges, partially offset by a

[5] Consistent with past practice (e.g., for 2007 rate application purposes, all budgeted costs, except for Stock Based Compensation, were based on Enbridge Inc.'s 2006 departmental budgets inflated by 2.2% (Source: MNP's Final Report dated February 27, 2007, p. 17)
[6] Consensus average of four forecasters (Bank of Montreal, Royal Bank, TD Bank and CIBC) of Alberta all-items CPI for 2008 (Economic Outlook, Summer/Fall 2007)
[7] 2008 consensus forecast for Ontario all-items CPI of 2% (Economic Outlook, Spring 2007) plus 3%.
[8] 2008 consensus forecast for Ontario all-items CPI of 2% (Economic Outlook, Spring 2007) plus 10%

reduction in the Return on Invested Capital, as summarized in the table below:

Nature of Charge	Year 2008 over Year 2007 Change Increase/(Decrease)	
	($M)	(%)
Primary Services	0.2	2.1
Direct	0.9	12.1
Return on Invested Capital	(0.1)	(33.8)
Net Increase	1.0	5.6

- The single most important factor driving the net increase in the aggregate corporate cost allocation amount for 2008 is the net increase in the Stock Based Compensation Charge of $1.5 million, primarily due to the initial flow through in 2008 of the costs associated with the introduction in late calendar 2006 of Restricted Stock Units (RSUs) to the employee compensation package (increase of $1.3 million)
- The following table, which provides a breakdown of the SBC charge to EGD by Stock Options, Performance Stock Units (PSUs) and RSUs, demonstrates that the net increase in the SBC charge in 2008 is almost entirely attributable to the addition of the RSUs

SBC Category[9]	2007($)	2008($)	Variance($)
Stock Options	1,224,682	1,114,869	(109,813)
PSUs	438,567	677,898	239,331
RSUs	-	1,329,247	1,329,247
Total	1,663,249	3,122,013	1,458,764

- While RSUs were introduced in late calendar 2006, none of the 2007 RSU costs were directly allocated to EGD in EB-2006-0034 because of the lag in RCAM recognition until 2008 due to budgeting cycle

Individual Service Threshold:

- The individual service threshold is triggered where the corporate cost allocation to any specific service or any direct charge increases in any one year by an amount greater than the CPI plus 10% and the increase is greater than $50,000.

[9] There are three main Long Term Incentive Plan (LTIP) vehicles at EGD: Incentive Stock Option Plan (ISOP), Performance Stock Unit Plan (PSUP) and Restricted Stock Unit Plan (RSUP). Under the PSUP and RSUP, a number of units are granted and paid out in cash at the end of the 3-year term (PSUs are granted to Vice President level and above, and RSUs are granted to Managers and Directors (and can be granted on a discretionary basis))

- The individual service threshold for 2008 of 12% and an amount greater than $50,000 has been triggered for the following seven (7)services/direct charges:
  - Employee Development
  - HRIS Management and Technical Support
  - Legal Advice
  - Records and Information Management
  - Risk Assessment and Management
  - Audit Fees
  - Stock Based Compensation

- For the above-noted individual services and direct charges where the materiality threshold has been exceeded, a description of the drivers for the increase and a copy of the most current service schedule for the service/charge in question are provided in Attachments 3 (variance analysis, yellow highlighted areas) and 4 respectively.

- Attachment 3, the variance analysis schedule, also contains explanations for selected other large increases (where the individual service or direct charge exhibits an increase greater than 12% from 2007 to 2008 and the amount is in close proximity to the materiality threshold of $50K) and large decreases (where the individual service or direct charge exhibits a decrease greater than -12% from 2007 to 2008, with a materiality threshold of -$50K)

Service Update:

- As agreed**,** the Company is obliged to give the consultative notice of any service which is discontinued in its entirety, and to provide the consultative with a copy of the service schedule for any new service or direct charge which is undertaken or incurred in 2008 and beyond. In this connection, the Company confirms that in 2008:
  - No service has been discontinued in its entirety[10]
  - No new service or direct charge has been undertaken or incurred

MNP's Recommendations:

- As agreed, the Company is also obliged to provide the consultative with notice of its implementation of any of the recommendations made by Meyers Norris Penny LLP in its report dated February 28, 2007.
  - This topic will be dealt with as a separate agenda item for the October 17th meeting and will formally be addressed by the Company at that time

[10] Again in 2008, the following Primary Services are not required by EGD: Aerial Pipeline Surveillance, External Communications, Gas Accounting, Gas Contract Accounting, Internal Employee Communications, Pension Plan Asset Management and Administration, Reservoir Engineering and Tax Advice.

Regulatory Cost Allocation Methodology (RCAM) - UPDATE REPORT FOR 2009

(October 2, 2009)

Introduction:

One of the issues in the 2007 rate case[1] was issue 3.6: Does the revised RCAM conform to the Board's directives in the EB-2005-0001 Decision?

The OEB issued a procedural order indicating that this matter would be considered as a second phase of EGD's 2007 rate application hearing.

In the first phase of the hearing the Board accepted, as part of the "completely settled package", the parties' agreement on issue 3.7 which was the quantum of the RCAM allocation for 2007 ($18.1 million). A supplementary Settlement Agreement was filed with the Board on September 26th, 2007 and presented to the Board at an oral hearing on September 27th, 2007. The Board accepted the Supplemental Agreement during the hearing. The parties[2] were able to reach an agreement on all outstanding issues with respect to the RCAM except the cost of raising equity and the cost of stock options. The OEB's Decision with Reasons dated May 20, 2008 dealt with those two issues.

As per the terms of the supplementary Settlement Agreement, the parties agreed that the corporate cost allocation consultative[3] would be continued, and commencing in 2008 and for each year that the Company operates under an incentive rate regulation regime, EGD has agreed to provide certain information to the intervenors in the event that certain thresholds, as defined in the subject agreement, were triggered.

2009 RCAM Report:

Given the thresholds set out in the RCAM Supplementary Settlement Agreement dated September 27, 2007 (RCAM Agreement) are exceeded, this report represents the second report made pursuant to the RCAM Agreement. A copy of the RCAM Supplementary Settlement Proposal, dated September 27, 2007, is attached for the reader's ready reference.

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[1] Board File No. EB-2006-0034

[2] Intervenors: Consumers' Council of Canada, Energy Probe Research Foundation, Industrial Gas Users Association, School Energy Coalition and Vulnerable Energy Consumers Coalition.

[3] Comprised of the intervenor groups identified in footnote 2 as well as Vince DeRose, now representing the Canadian Manufacturers & Exporters, a non-participating party in the negotiation and partial settlement of issue 3.6 in EGD's 2007 rate case with respect to the regulatory cost allocation methodology (RCAM

The information contained in this report has been prepared in accordance with the terms and conditions of the subject agreement and is being provided to members of the RCAM consultation group. It is understood that all responses and all information provided to the consultation group members may be shared with other intervenors. However, it is further understood that all information so provided will be on a without prejudice basis and will be treated as if such responses and information had been provided by the Company during a Settlement Conference.

The 2009 information package consists of this report and the following accompanying documents:

Attachment	Document Description
1	A summary table setting out the direct, common and total costs allocated to the Company for each service and all direct charges assigned to the Company for the years 2008 and 2009[4].
1(a)	A schedule providing details of the 2009[5] costs for each service, including EI's total loaded departmental cost, the total amount allocated to the primary service, the direct and common allocations to EGD and the direct and common allocations to other affiliates (Source: Appendix A to Schedule 2(d), the 2009 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)
1(b)	Four (4) accompanying schedules to Attachment 1(a) providing further details on 2009 costs: Primary Service Costs; General Expenses and Direct Charges; Return on Invested Capital; and EI's Support Services Cost (Source: Accompanying Schedules to Appendix A to Schedule 2(d), the 2009 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)[6]
2	A table setting out the departmental O & M budgets for Enbridge Inc. by primary service for the years 2008 and 2009[7]
3	2009 versus 2008 RCAM Allocations Variance Analysis

[4] The corresponding information for 2008 was provided to the RCAM consultation group members in an accompanying schedule, Attachment 1 – Restated, to the 2008 RCAM Update Report, arising from the intervenor workshop/meeting held on October 17, 2008
[5] The corresponding information for 2008 was provided to the consultation group members in an accompanying schedule, Attachment 1(a), to the 2008 RCAM Update Report
[6] The corresponding information for 2008 was provided to the consultation group members in an accompanying schedule, Attachment 1(b), to the 2008 RCAM Update Report
[7] The corresponding information for 2008 was provided to the RCAM consultation group members in an accompanying schedule, Attachment 2 – Restated, to the 2008 RCAM Update Report, arising from the intervenor workshop/meeting held on October 17, 2008

Background Information:

- There have been no changes in methodology in the past year.
- Enbridge Inc.'s RCAM departmental budgets increased by $15.9 million or 11.0% to $161.1 million in 2009 from $145.2 million in 2008:
  - For 2009[8], budgeted costs were based on Enbridge Inc.'s 2008 departmental budgets inflated by 1.83%[9].
- The aggregate threshold for 2009 in respect of RCAM cost allocations to EGD is 4.7%[10].
- The individual service threshold for 2009 is 11.7% and greater than $50,000.[11]
- As discussed last year, there is typically a lag in RCAM recognition of changes in EI's budgeted costs from year to year having regard to the inherent time conflict between EGD's regulatory compliance cycle and EI's budgeting cycle. For any given year, the RCAM budget, which is based on EI's departmental budgets for the previous year as adjusted for inflation, is developed well in advance of the availability of EI's actual departmental budgets for the year in question. For example, the RCAM allocations for 2009 are based on an RCAM budget of $161.1 million (i.e., EI's corporate budget for 2008 inflated by 1.83%); whereas, EI's actual corporate budget for 2009 is $205.7 million. Specifically for 2009, continuation of the current practice should result in lower RCAM allocations than otherwise because the RCAM budgetary base is understated, holding all else constant.
  - The precedent was established in the 2007 rate case because of the need to advance the budget cycle for regulatory budget development purposes
  - This occurs because of the need for EGD to adhere to the Annual Review Process timelines specified in the ISA and to meet its regulatory compliance requirements; however, during IRM EI's preliminary budget, at a minimum, is available as an alternative for the purpose of calculating/updating the RCAM allocations in a given year
  - This can result in material changes in RCAM allocations for individual services and direct charges year over year

[8] Consistent with past practice (i.e., for 2007 rate application purposes, budgeted costs were based on Enbridge Inc.'s 2006 departmental budgets inflated by 2.2% and for 2008 RCAM report-back purposes, budgeted costs were based on Enbridge Inc.'s 2007 departmental budgets inflated by 3.73%

[9] Consensus average of four forecasters of Alberta all-items CPI for 2009

[10] 2009 consensus forecast for Ontario all-items CPI of 1.7% (Economic Outlook, Spring 2008) plus 3%.

[11] 2009 consensus forecast for Ontario all-items CPI of 1.7% (Economic Outlook, Spring 2008) plus 10%

Aggregate Threshold:

- The aggregate corporate cost allocation amount for 2008 was $19.1 million. This amount has increased in 2009 by $2.1 million or 10.9% to $ $21.2 million. Thus, the aggregate threshold of 4.7% for 2009 has been triggered.
- The drivers for the increase in the overall RCAM cost allocation amount which contribute to the aggregate threshold being exceeded for 2009 are as follows:
    - A combination of a significant net increase in flow through costs or Total Direct Charges (i.e., centrally managed costs on behalf of EGD – e.g., insurance, audit, SBC, - directly billed) and an increase in the Return on Invested Capital, partially offset by an overall reduction in Total Primary Service Charges, as summarized in the table below:

Nature of Charge	**Year 2009 over Year 2008 Change Increase/(Decrease)**	
	($M)	**(%)**
Total Primary Services	(0.5)	(4.3)
Total Direct Charges	2.1	25.3
Return on Invested Capital	0.4	214.5
Net Increase	2.1[12]	10.9

    - As noted in the above table, flow through costs are up $2.1 million or 25.3%, principally Stock Based Compensation and Insurance Premiums
    - Not unlike last year, the single most important factor driving the net increase in the aggregate corporate cost allocation amount for 2009 is the net increase in the EGD Stock Based Compensation Charge of $1.14 million
    - The following table provides a breakdown of the SBC charge to EGD by Stock Options, Performance Stock Units (PSUs) and Restricted Stock Units (RSUs)

SBC Category[13]	**2008($)**	**2009($)**	**Variance($)**
Stock Options	1,114,869	1,577,529	462,660
PSUs	677,898	417,044	(260,854)
RSUs	1,329,247	2,267,467	938,220
Total	**3,122,013**	**4,262,039**	**1,140,026**

[12] May not add due to rounding
[13] As noted last year, there are three main Long Term Incentive Plan (LTIP) vehicles at EGD: Incentive Stock Option Plan (ISOP), Performance Stock Unit Plan (PSUP) and Restricted Stock Unit Plan (RSUP). Under the PSUP and RSUP, a number of units are granted and paid out in cash at the end of the 3-year term (PSUs are granted to Vice President level and above, and RSUs are granted to Managers and Directors (and can be granted on a discretionary basis))

Individual Service Threshold:

- The individual service threshold is triggered where the corporate cost allocation to any specific service or any direct charge increases in any one year by an amount greater than the CPI plus 10% and the increase is greater than $50,000.
- The individual service threshold for 2009 of 11.7% and an amount greater than $50,000 has been triggered for the following seven (7) services and four (4) general expense &direct charge items:
  (a) Services (7)
    - Employee Development - Increase of 68.2% and $222.6K;
    - Expense System Management & Technical Support (Oracle Expense, formerly Necho Navigator) - Increase of 94.3% and $123.9K;
    - Human Resource Advice - Increase of 81.8% and $75.9K;
    - Industry Relations & Corporate Social Responsibility (CSR) - Increase of 68.1% and $125.9K;
    - Legal Advice - Increase of 18.9% and $69.K;
    - Planning, Management & Execution of Internal Audits - Increase of 115.2% and $101.1K; and
    - Risk Assessment and Management - Increase of 10.6% and $66.2K.

  (b) General Expenses & Direct Charges (4)
    - Direct EFS Charge - Reduction in credit of 73.3% and $338.3K;
    - Insurance Premiums - Increase of 11.6% and $475.0K;
    - Audit Fees - Increase of 19.5% and $204.1K; and
    - EGD Stock Based Compensation - Increase of 36.5% and $1.1M
- As well, the Return on Invested Capital, which is included as a separate charge in RCAM, has exceeded the individual service threshold for 2009.
- For the above-noted individual services and general expenses/direct charges where the materiality threshold has been exceeded, a description of the drivers for the increase for the affected individual service, general expense or direct charge are provided in Attachment 3 (variance analysis, yellow highlighted areas)
- Attachment 3, the variance analysis schedule, also contains an explanation for Employee and Labour Relations Service[14] because this service exhibits an increase greater than 11.7% from 2008 to 2009 and the amount is in close proximity to the materiality threshold of $50K)

Service Update:

- As agreed**,** the Company is obliged to give the consultative notice of any service which is discontinued in its entirety, and to provide the consultative

[14] Increase of 16.3% and $48.8K

with a copy of the service schedule for any new service or direct charge which is undertaken or incurred in 2009 and beyond. In this connection, the Company confirms that in 2009:

- No service has been discontinued in its entirety[15]
- No new service or direct charge has been undertaken or incurred

MNP's Recommendations:

- As agreed, the Company is also obliged to provide the consultative with notice of its implementation of any of the recommendations made by Meyers Norris Penny LLP in its report dated February 28, 2007.
  - An update on current developments and the Company's plans will be dealt with as a separate agenda item for the October 5th meeting and will formally be addressed by the Company at that time

[15] Since 2007, the following Primary Services are not required by EGD: Aerial Pipeline Surveillance, External Communications, Gas Accounting, Gas Contract Accounting, Internal Employee Communications, Pension Plan Asset Management and Administration, Reservoir Engineering and Tax Advice.

Regulatory Cost Allocation Methodology (RCAM) - UPDATE REPORT FOR 2010

(December 16, 2010)

Introduction:

One of the issues in the 2007 rate case[1] was issue 3.6: Does the revised RCAM conform to the Board's directives in the EB-2005-0001 Decision?

The OEB issued a procedural order indicating that this matter would be considered as a second phase of EGD's 2007 rate application hearing.

In the first phase of the hearing the Board accepted, as part of the "completely settled package", the parties' agreement on issue 3.7 which was the quantum of the RCAM allocation for 2007 ($18.1 million). A supplementary Settlement Agreement was filed with the Board on September 26th, 2007 and presented to the Board at an oral hearing on September 27th, 2007. The Board accepted the Supplemental Agreement during the hearing. The parties[2] were able to reach an agreement on all outstanding issues with respect to the RCAM except the cost of raising equity and the cost of stock options. The OEB's Decision with Reasons dated May 20, 2008 dealt with those two issues.

As per the terms of the supplementary Settlement Agreement, the parties agreed that the corporate cost allocation consultative[3] would be continued, and commencing in 2008 and for each year that the Company operates under an incentive rate regulation regime, EGD has agreed to provide certain information to the intervenors in the event that certain thresholds, as defined in the subject agreement, are triggered.

2010 RCAM Report:

Given the thresholds set out in the RCAM Supplementary Settlement Agreement dated September 27, 2007 (RCAM Agreement) are exceeded, this report represents the third report made pursuant to the RCAM Agreement.

The information contained in this report has been prepared in accordance with the terms and conditions of the subject agreement and is being provided to members of the RCAM consultation group. It is understood that all responses

[1] Board File No. EB-2006-0034
[2] Intervenors: Consumers' Council of Canada, Energy Probe Research Foundation, Industrial Gas Users Association, School Energy Coalition and Vulnerable Energy Consumers Coalition.
[3] Comprised of the intervenor groups identified in footnote 2 as well as Vince DeRose, now representing the Canadian Manufacturers & Exporters, a non-participating party in the negotiation and partial settlement of issue 3.6 in EGD's 2007 rate case with respect to the regulatory cost allocation methodology (RCAM)

and all information provided to the consultation group members may be shared with other intervenors. However, it is further understood that all information so provided will be on a without prejudice basis and will be treated as if such responses and information had been provided by the Company during a Settlement Conference.

Updated Scenario Analysis – 2009 RCAM Allocations:

Further to the discussion at the October 5, 2009 review meeting about the merits of EGD continuing with the then current practice of using EI's proxy budget (i.e., previous year's budget inflated), rather than using the current year's budget, as the cost basis for determining RCAM allocations to EGD in any given year, a scenario analysis was undertaken in respect of the 2009 RCAM allocations.[4]

The analysis indicated that, by substituting EI's approved RCAM budget for 2009 in lieu of EI's RCAM proxy budget for 2009[5] everything else held constant, as the basis for determining the 2009 RCAM allocations to EGD, the total RCAM allocation to EGD would have been $22,994,363 (or $23.0M rounded) under this scenario.[6]

Upon subsequent examination, it has been determined that this calculation, which was provided to the RCAM consultation group members on December 24, 2009[7], was based on incomplete analysis and required updating. One of the main drivers for the revised calculation was the need to update the EFS True Up calculation. The updated scenario analysis indicates that the total RCAM allocation to EGD for 2009 would have been $22,602,935 (or $22.6M rounded), if the RCAM calculations were based on EI's approved budget for 2009. This represents a small net reduction of $391.4K when compared to the previous version of the calculation provided to the intervenors last December.

In this regard, the Company is now providing a summary financial table that sets out the results of the updated 2009 scenario analysis by individual service and direct charge. As well, the Company is providing a financial schedule that compares the 2009 RCAM Allocations to EGD based on EI's RCAM Proxy Budget for 2009 versus EI's RCAM Approved Budget for 2009.

Updated Cost Inputs for 2010:

[4] In response to an undertaking given to the intervenors by the Company arising from the review meeting held on October 5, 2009.
[5] That is, EI's approved RCAM budget for 2008 inflated by 1,83%
[6] This compares to the $21,115,958 (or $21.1M rounded) final RCAM figure accepted by the Company for 2009 as determined using EI's proxy budget for 2009.
[7] The subject scenario analysis was provided to the consultation group members in an accompanying schedule to the 2009 RCAM Supplementary Report dated December 2009.

At the October 5, 2009 review meeting, the Company expressed concern about continuing to rely on stale-dated EI cost inputs[8] for the purpose of determining annual RCAM allocations on a go forward basis, and signaled its intention, commencing in 2010, to have future calculations based on more current budget information. This change has been made for 2010 and the 2010 RCAM allocation amounts have been determined using EI's approved budget for the current year. As a consequence, in order to effect an "apples-to-apples" comparison the year 2010 over year 2009 variance analysis/explanations presented in this report are based on a comparison of RCAM allocations calculated for 2009 and 2010 using EI's approved budget for each of the respective years.

2010 Information Package

The 2010 information package consists of this report and the following accompanying documents:

Document Description	Comments
Updated Scenario Analysis- 2009 RCAM Allocations to EGD	• Correction to the illustrative schedule provided in December 2009 that updates the 2009 RCAM charges to EGD resulting from the use of EI's approved RCAM budget for 2009 as a substitute for the EI 2009 RCAM proxy budget
Comparison of 2009 RCAM Allocations to EGD Under Two Different Scenarios	• A financial schedule that shows the impact on 2009 RCAM allocations to EGD resulting from the substitution of EI's Approved RCAM Budget for 2009 for EI's Proxy RCAM Budget for 2009, everything else held constant.
Attachment 1 to the 2010 RCAM Report	• A summary table setting out the direct, common and total costs allocated to the Company for each service and all direct charges assigned to the Company for the years 2009 and 2010[9].

[8] The precedent was established in the 2007 rate case because of the need to advance the budget cycle for regulatory budget development purposes. As discussed last year, there is typically a lag in RCAM recognition of changes in EI's budgeted costs from year to year having regard to the inherent time conflict between EGD's regulatory compliance cycle and EI's budgeting cycle. For any given year, the RCAM budget, which is based on EI's departmental budgets for the previous year as adjusted for inflation, is developed well in advance of the availability of EI's actual departmental budgets for the year in question. For example, the RCAM allocations for 2009 were based on an RCAM budget of $161.1 million (i.e., EI's corporate budget for 2008 inflated by 1.83%); whereas, EI's actual corporate budget for 2009 was $180.8 million. As noted in an accompanying schedule to this report, this has resulted in lower RCAM allocations to EGD of $1.5 million in 2009. Specifically for 2009, reliance on stale-dated cost inputs resulted in lower RCAM allocations than otherwise because the RCAM budgetary base was understated, holding all else constant.

[9] The corresponding information for 2009 was provided to the RCAM consultation group members in Attachment 1 to the 2009 RCAM Report dated October 2, 2009; and an

Document Description	Comments
Attachment 1(a) to the 2010 RCAM Report	• A schedule providing details of the 2010[10] costs for each service, including EI's total loaded departmental cost, the total amount allocated to the primary service, the direct and common allocations to EGD and the direct and common allocations to other affiliates (Source: Appendix A to Schedule 2(e), the 2010 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)
Attachment 1(b) to the 2010 RCAM Report	• Four (4) accompanying schedules to Attachment 1(a) providing further details on 2010 costs: Primary Service Costs; General Expenses and Direct Charges; Return on Invested Capital; and EI's Support Services Cost (Source: Accompanying Schedules to Appendix A to Schedule 2(e), the 2010 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)[11]
Attachment 2 to the 2010 RCAM Report	• A table setting out the RCAM (departmental O & M) budgets for Enbridge Inc. by primary service for the years 2009 and 2010[12]
Attachment 3 to the 2010 RCAM Report	• 2010 versus 2009 RCAM Allocations Variance Analysis

Background Information:

- There have been no changes in methodology in the past year.
- Enbridge Inc.'s approved RCAM departmental budgets increased by $20.3 million or 11.2% to $201.1 million in 2010 from $180.8 million in 2009.[13]
- The aggregate threshold for 2010 in respect of RCAM cost allocations to EGD is 4.8%[14].
- The individual service threshold for 2010 is 11.8% and greater than $50,000.[15]

Aggregate Threshold:

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accompanying schedule to the 2009 Supplementary RCAM Report dated December 2009, entitled: "Attachment 1(a) to the 2009 RCAM Report – Restated".

[10] The corresponding information for 2009 was provided to the consultation group members in Attachment 1(a) to the 2009 RCAM Report dated October 2, 2009 as revised/updated in the accompanying schedule to the 2009 Supplementary RCAM Report dated December 2009 noted in footnote 4 above.

[11] The corresponding information for 2009 was provided to the consultation group members in Attachment 1(b), to the 2009 RCAM Report dated October 2, 2009.

[12] The corresponding information for 2009 was provided to the RCAM consultation group members in Attachment 2 to the 2009 RCAM Report dated October 2, 2009.

[13] Please see Attachment 2 to this report for particulars.

[14] 2010 consensus forecast for Ontario all-items CPI of 1.8% (Economic Outlook, Spring 2009) plus 3%.

[15] 2010 consensus forecast for Ontario all-items CPI of 1.8% (Economic Outlook, Spring 2009) plus 10%

- The aggregate corporate cost allocation amount accepted by the Company for 2009 was $21.1 million. As noted earlier, this amount was determined using EI's Proxy Budget for 2009. As further noted earlier, this amount would have increased by $1.5 million to $22.6 million in 2009 if the corporate cost allocations were calculated using more current cost inputs. On an approved budget comparison basis, the $22.6 million figure has increased in 2010 by $1.7 million or 7.4% to $24.3 million. Thus, the aggregate threshold of 4.8% for 2010 has been triggered.
- The drivers for the increase in the overall RCAM cost allocation amount which contribute to the aggregate threshold being exceeded for 2010 are as follows:
    - A combination of a net increase in flow through costs or Total Direct Charges (i.e., centrally managed costs incurred by EI on behalf of EGD like insurance, audit, SBC, that are directly billed) and an overall increase in Total Primary Service Charges, partially offset by a reduction in the Return on Invested Capital, as summarized in the table below:

Nature of Charge	**Year 2010 over Year 2009 Change Increase/(Decrease)**	
	($M)	**(%)**
Total Primary Services	1.0	8.2
Total Direct Charges	0.8	8.6
Return on Invested Capital	(0.2)	(29.2)
Net Increase	1.7[16]	7.4

    - As noted in the above table, flow through costs are up $0.8 million or 8.6%, principally due to increases in Stock Based Compensation Charges and Insurance Premium costs.
    - The following table provides a breakdown of the SBC charge to EGD by SBC Category: Stock Options, Performance Stock Units (PSUs) and Restricted Stock Units (RSUs)

[16] May not add due to rounding

SBC Category[17]	2009($)	2010 ($)	Variance($)	Variance (%)
Stock Options	1,294,639	1,340,851	46,213	3.6
PSUs	521,429	627,181	105,752	20.3
RSUs	2,514,135	2,874,365	360,229	14.3
Total	**4,330,209[18]**	**4,842,397**	**512,188[18]**	**11.8**

Individual Service Threshold:

- The individual service threshold is triggered where the corporate cost allocation to any specific service or any direct charge increases in any one year by an amount greater than the CPI plus 10% and the increase is greater than $50,000.
- The individual service threshold for 2010 of 11.8% and an amount greater than $50,000 has been strictly triggered for the following six (6) services and two (2) general expense & direct charge items:
  (a) Services (6)
    - Employee Development - Increase of 15.2% and $105.8K;
    - Enterprise IT Program Management - Increase of 49.0% and $135.9K;
    - Gas Supply, Storage, and Transportation Strategy - Increase of 28.5% and $51.3K;
    - HRIS Program Management and Development – Increase of 104.2% and $788.8K;
    - Human Resource Advice - Increase of 22.8% and $50.5K; and
    - Legal Advice - Increase of 35.0% and $194.0K.

  (b) General Expenses & Direct Charges (2)
    - Insurance Premiums - Increase of 13.3% and $608.3K; and
    - EGD Stock Based Compensation Charge - Increase of 11.8% and $512.2K.
- For the above-noted individual services and general expenses/direct charges where the materiality threshold has been exceeded, a description of the drivers for the increase for the affected individual service, general expense or direct charge are provided in Attachment 3 (2010 variance analysis, yellow highlighted areas)
- Attachment 3, the variance analysis schedule, also provides an explanation for Total Compensation and Benefits Service[19] because this service exhibits an increase close to the 11.8% trigger from 2009 to 2010 and the amount exceeds the materiality threshold of $50K.

[17] There are three main Long Term Incentive Plan (LTIP) vehicles applicable at EGD in 2009 and 2010: Incentive Stock Option Plan (ISOP), Performance Stock Unit Plan (PSUP) and Restricted Stock Unit Plan (RSUP). Under the PSUP and RSUP, a number of units are granted and paid out in cash at the end of the 3-year term (PSUs are granted to Vice President level and above, and RSUs are granted to Managers and Directors (and can be granted on a discretionary basis))
[18] May not add due to rounding
[19] Increase of 11.0% and $130.6K

Service Update:

- As agreed**,** the Company is obliged to give the consultative notice of any service which is discontinued in its entirety, and to provide the consultative with a copy of the service schedule for any new service or direct charge which is undertaken or incurred in 2010 and beyond. In this connection, the Company confirms that in 2010:
  - No service has been discontinued in its entirety[20]
  - No new service or direct charge has been undertaken or incurred

MNP's Recommendations:

- As agreed, the Company is also obliged to provide the consultative with notice of its implementation of any of the recommendations made by Meyers Norris Penny LLP in its report dated February 28, 2007.
  - An update on current developments and the Company's plans will be dealt with as a separate agenda item for the December 22nd meeting and will formally be addressed by the Company at that time

[20] Since 2007, the following Primary Services are not required by EGD: Aerial Pipeline Surveillance, External Communications, Gas Accounting, Gas Contract Accounting, Internal Employee Communications, Pension Plan Asset Management and Administration, Reservoir Engineering and Tax Advice.

Regulatory Cost Allocation Methodology (RCAM) - UPDATE REPORT FOR 2011

(January 31, 2012)

Introduction:

One of the issues in the 2007 rate case[1] was issue 3.6: Does the revised RCAM conform to the Board's directives in the EB-2005-0001 Decision?

The OEB issued a procedural order indicating that this matter would be considered as a second phase of EGD's 2007 rate application hearing.

In the first phase of the hearing the Board accepted, as part of the "completely settled package", the parties' agreement on issue 3.7 which was the quantum of the RCAM allocation for 2007 ($18.1 million). A supplementary Settlement Proposal was filed with the Board on September 26th, 2007 and presented to the Board at an oral hearing on September 27th, 2007. The Board accepted the Supplemental Agreement during the hearing. The parties[2] were able to reach an agreement on all outstanding issues with respect to the RCAM except the cost of raising equity and the cost of stock options and parties to the Settlement Agreement accepted that EGD had complied with the Board's directives in the 2006 Test Year decision[3]. The OEB's Decision with Reasons dated May 20, 2008 dealt with those two issues.

As per the terms of the supplementary Settlement Agreement, the parties agreed that the corporate cost allocation consultative[4] would be continued, and commencing in 2008 and for each year that the Company operates under an incentive rate regulation regime, EGD has agreed to provide certain information to the intervenors in the event that certain thresholds, as defined in the subject agreement, are triggered.

[1] Board File Number EB-2006-0034
[2] Intervenors: Consumers' Council of Canada, Energy Probe Research Foundation, Industrial Gas Users Association, School Energy Coalition and Vulnerable Energy Consumers Coalition.
[3] EB-2005-0001/EB-2005-0437 Decision with Reasons dated February 9, 2006
[4] Comprised of the intervenor groups identified in footnote 2 as well as Vince DeRose, now representing the Canadian Manufacturers & Exporters, a non-participating party in the negotiation and partial settlement of issue 3.6 in EGD's 2007 rate case with respect to the regulatory cost allocation methodology (RCAM)

2011 RCAM Report:

Given the thresholds set out in the RCAM Supplementary Settlement Agreement dated September 27, 2007 (RCAM Agreement) are exceeded, this report represents the fourth report made pursuant to the RCAM Agreement.

The information contained in this report has been prepared in accordance with the terms and conditions of the subject agreement and is being provided to members of the RCAM consultation group. It is understood that all responses and all information provided to the consultation group members may be shared with other intervenors. However, it is further understood that all information so provided will be on a without prejudice basis and will be treated as if such responses and information had been provided by the Company during a Settlement Conference.

2011 Information Package:

The 2011 information package consists of this report and the following accompanying documents:

Document Description	Comments
Attachment 1 to the 2011 RCAM Report	• A summary table setting out the direct, common and total costs allocated to the Company for each service and all direct charges assigned to the Company for the years 2010 and 2011[5].
Attachment 1(a) to the 2011 RCAM Report	• A schedule providing details of the 2011[6] costs for each service, including EI's total loaded departmental cost, the total amount allocated to the primary service, the direct and common allocations to EGD and the direct and common allocations to other affiliates (Source: Appendix A to Schedule 2(a) of the ISA between EGD and EI dated January 1, 2011, the 2011 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)
Attachment 1(b) to the 2011 RCAM Report	• Four (4) accompanying schedules to Attachment 1(a) providing further details on 2011 costs: Primary Service Costs; General Expenses and Direct Charges; Return on Invested Capital; and EI's Support Services Cost (Source: Accompanying Schedules to Appendix A to Schedule 2(a) of the ISA between EGD and EI dated January 1, 2011, namely, the 2011 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)[7]

[5] The corresponding information for 2010 was provided to the RCAM consultation group members in Attachment 1 to the 2010 RCAM Report dated December 16, 2010.
[6] The corresponding information for 2010 was provided to the consultation group members in Attachment 1(a) to the 2010 RCAM Report dated December 16, 2010.
[7] The corresponding information for 2010 was provided to the RCAM consultation group members in Attachment 1(b), to the 2010 RCAM Report dated December 16, 2010.

Document Description	Comments
Attachment 2 to the 2011 RCAM Report	• A table setting out the approved RCAM (departmental O & M) budgets for Enbridge Inc. by primary service for the years 2010 and 2011[8]
Attachment 3 to the 2011 RCAM Report	• 2011 versus 2010 RCAM Allocations Variance Analysis
Attachment 4 to the 2011 RCAM Report	• Continuity Statement of EI RCAM Budgets and Allocations to EGD for the period 2007-2011. Comprised of three schedules that updates for one additional year the 2007-2010 RCAM trend analysis provided to the intervenors in December 2010 upon the intervenors' request.

Background Information:

- There have been no changes in methodology in the past year.
- For the reasons discussed at the 2010 RCAM review meeting held on December 22, 2010, the 2011 RCAM allocations to EGD have been determined using EI's approved RCAM budget for 2011 as the cost basis. This is consistent with the practice adopted, commencing with the calculation of the RCAM allocations to EGD for 2010, of using EI's current year's budget as the budget basis for determining RCAM allocations to EGD in any given year, rather than the previous practice of using EI's proxy budget (i.e., previous year's budget inflated) as the cost basis.
- The Company has renewed its Intercorporate Services Agreement with Enbridge Inc. for a further period of five years commencing on January 1, 2011 (2011 ISA). The Parties have executed a confirmation notice to evidence the Parties' agreement to the cost allocations for 2011 (2011 RCAM Confirmation Notice), which has been incorporated into and forms part of the Renewal Agreement. The executed RCAM Confirmation Notice became Schedule 2(a) for 2011.
- Enbridge Inc.'s approved RCAM departmental budgets increased by $37.3 million or 18.6% to $238.4 million in 2011 from $201.1 million in 2010.[9]
- The aggregate threshold for 2011 in respect of RCAM cost allocations to EGD is 5.1%[10].
- The individual service threshold for 2011 is 12.1% and greater than $50,000.[11]

[8] The corresponding information for 2010 was provided to the RCAM consultation group members in Attachment 2 to the 2010 RCAM Report dated December 16, 2010.
[9] Please see Attachment 2 to this report for particulars.
[10] 2011 consensus forecast for Ontario all-items CPI of 2.1% per EGD's 2011 Budget Assumptions and Guidelines (Economic Outlook, Spring 2010) plus 3%.
[11] 2011 consensus forecast for Ontario all-items CPI of 2.1% per EGD's 2011 Budget Assumptions and Guidelines (Economic Outlook, Spring 2010) plus 10%

Aggregate Threshold:

- The aggregate corporate cost allocation amounts accepted by the Company for 2010 and 2011 were $24.3 million and $26.7 million respectively. Since the overall increase in 2011 was $2.4 million or 9.9%, the aggregate threshold of 5.1% for 2011 has been triggered.
- The drivers for the increase in the overall RCAM cost allocation amount which contribute to the aggregate threshold being exceeded for 2011 are as follows:
    - A combination of a net increase in flow through costs or Total Direct Charges (i.e., arising from centrally managed programs) and an overall increase in Total Primary Service Charges, partially offset by a reduction in the Return on Invested Capital, as summarized in the table below:

Nature of Charge	Year 2011 over Year 2010 Change Increase/(Decrease)	
	($M)	(%)
Total Primary Services	1.4	10.5
Total Direct Charges	1.1	10.3
Return on Invested Capital	(0.1)	(16.6)
Net Increase	2.4	9.9

    - As noted in the above table, flow through costs are up net $1.1 million or 10.3%, principally due to increases in EGD Stock Based Compensation Charges and Audit Fees, and, to a lesser extent, increased usage costs associated with the Risk Management System.
    - The following table provides a breakdown of the SBC charge to EGD by SBC Category: Stock Options, Performance Stock Units (PSUs) and Restricted Stock Units (RSUs)

SBC Category[12]	2011($)	2010 ($)	Variance($)	Variance (%)
Stock Options	1,361,895	1,340,851	21,044	1.6
PSUs	945,573	627,181	318,392	50.8
RSUs	4,105,763	2,874,365	1,231,398	42.8
Total	**6,413,231**	**4,842,397**	**1,570,834**	**32.4**

Individual Service Threshold:

[12] There are three main Long Term Incentive Plan (LTIP) vehicles applicable at EGD in 2010 and 2011: Incentive Stock Option Plan (ISOP), Performance Stock Unit Plan (PSUP) and Restricted Stock Unit Plan (RSUP). Under the PSUP and RSUP, a number of phantom units are granted and paid out in cash at the end of the 3-year term (PSUs are granted to Vice President level and above, and RSUs are granted to Managers and Directors (and can be granted on a discretionary basis))

- The individual service threshold is triggered where the corporate cost allocation to any specific service or any direct charge increases in any one year by an amount greater than the CPI plus 10% and the increase is greater than $50,000.
- The individual service threshold for 2011 of 12.1% and an amount greater than $50,000 has been strictly triggered for the following twelve (12) services and three (3) general expense & direct charge items:

  (a) Services (12)
  - Business Development – Increase of 21.3% and $93.6K;
  - Capital Market Financing & Access - Increase of 15.0% and $128.5K;
  - Consolidation and Planning System Technical Support (Khalix) – Increase of 23.1% and $113.9K;
  - Industry Relations & Corporate Social Responsibility (CSR) – Increase of 16.5% and $65.7K;
  - Employee Development - Increase of 49.5% and $397.6K;
  - Expense System Management & Technical Support (Oracle iExpense) – Increase of 43.3% and $72.4K;
  - HRIS Program Management and Development – Increase of 40.4% and $624.1K;
  - Human Resource Advice - Increase of and 30.2% and $82.1K;
  - Investor Services – Increase of 18.4% and $126.1K;
  - Risk Assessment and Management – Increase of 20.3% and $179.5K;
  - Strategic Planning - Increase of 30.3% and $59.1K; and
  - Employee and Labour Relations (Combined) – Increase of 20.4% and $93.4K.

  (b) General Expenses & Direct Charges (3)
  - Depreciation, Risk Management System – Increase of 398.8% and $55.1K;
  - Audit Fees - Increase of 21.7% and $244,2K; and
  - EGD Stock Based Compensation Charge - Increase of 32.4% and $1.6M.

- For the above-noted individual services and general expenses/direct charges where the materiality threshold has been exceeded, a description of the drivers for the increase for the affected individual service, general expense or direct charge are provided in Attachment 3 (2011 variance analysis, yellow highlighted areas)
- Attachment 3, the 2011 variance analysis schedule, also provides an explanation for the increase in the Total Compensation and Benefits Service[13] because this service, while exhibiting an increase below the

[13] Increase of 7.4% and $97.1K

12.1% trigger applicable from 2010 to 2011, experienced a dollar amount increase that exceeded the materiality threshold of $50K.

Service Update:

- As agreed**,** the Company is obliged to give the RCAM consultative notice of any service which is discontinued in its entirety, and to provide the consultative with a copy of the service schedule for any new service or direct charge which is undertaken or incurred in 2011 and beyond. In this connection, the Company confirms that in 2011:
  - No service has been discontinued in its entirety[14]
  - No new service or direct charge has been undertaken or incurred

MNP's Recommendations:

- As agreed, the Company is also obliged to provide the RCAM consultative with notice of its implementation of any of the recommendations made by Meyers Norris Penny LLP in its final report dated February 28, 2007.
  - There have been no new major developments since the last report.
  - As noted in the last RCAM review meeting held on December 22, 2010 and in keeping with the Company's ongoing commitment to enhance the internal processes, it remains EGD's intention to implement the launch of an annual customer satisfaction survey questionnaire to be completed by service recipients as part of the formal 2012 RCAM review process currently underway.
  - As part of the update study MNP will be determining the status of those recommendations made in MNP's 2007 independent valuation of EGD's RCAM methodology.

[14] Since 2007, the following Primary Services are not required by EGD: Aerial Pipeline Surveillance, External Communications, Gas Accounting, Gas Contract Accounting, Internal Employee Communications, Pension Plan Asset Management and Administration, Reservoir Engineering and Tax Advice.

Regulatory Cost Allocation Methodology (RCAM) - UPDATE REPORT FOR 2012

(May 2, 2012)

Introduction:

One of the issues in the 2007 rate case[1] was issue 3.6: Does the revised RCAM conform to the Board's directives in the EB-2005-0001 Decision?

The OEB issued a procedural order indicating that this matter would be considered as a second phase of EGD's 2007 rate application hearing.

In the first phase of the hearing the Board accepted, as part of the "completely settled package", the parties' agreement on issue 3.7 which was the quantum of the RCAM allocation for 2007 ($18.1 million). A supplementary Settlement Proposal was filed with the Board on September 26th, 2007 and presented to the Board at an oral hearing on September 27th, 2007. The Board accepted the Supplemental Agreement during the hearing. The parties[2] were able to reach an agreement on all outstanding issues with respect to the RCAM except the cost of raising equity and the cost of stock options and parties to the Settlement Agreement accepted that EGD had complied with the Board's directives in the 2006 Test Year decision[3]. The OEB's Decision with Reasons dated May 20, 2008 dealt with those two issues.

As per the terms of the supplementary Settlement Agreement, the parties agreed that the RCAM consultation group[4] would be continued, and commencing in 2008 and for each year that the Company operates under an incentive rate regulation regime, EGD has agreed to provide certain information to the intervenors in the event that certain thresholds, as defined in the subject agreement, are triggered.

[1] Board File Number EB-2006-0034
[2] Intervenors: Consumers' Council of Canada, Energy Probe Research Foundation, Industrial Gas Users Association, School Energy Coalition and Vulnerable Energy Consumers Coalition.
[3] EB-2005-0001/EB-2005-0437 Decision with Reasons dated February 9, 2006
[4] Comprised of the intervenor groups identified in footnote 2 as well as Vince DeRose, now representing the Canadian Manufacturers & Exporters, a non-participating party in the negotiation and partial settlement of issue 3.6 in EGD's 2007 rate case with respect to the regulatory cost allocation methodology (RCAM)

2012 RCAM Report:

Given that the thresholds set out in the RCAM Supplementary Settlement Agreement dated September 27, 2007 (RCAM Agreement) are exceeded for 2012, this report represents the fifth and final report made pursuant to the RCAM Agreement.

The information contained in this report has been prepared in accordance with the terms and conditions of the subject agreement and is being provided to members of the RCAM consultation group. It is understood that all responses and all information provided to the consultation group members may be shared with other intervenors. However, it is further understood that all information so provided will be on a without prejudice basis and will be treated as if such responses and information had been provided by the Company during a Settlement Conference.

2012 Information Package:

The 2012information package consists of this report and the following accompanying documents:

Document Description	Comments
Attachment 1 to the 2012 RCAM Report	• A summary table setting out the direct, common and total costs allocated to the Company for each service and all direct charges assigned to the Company for the years 2011 and 2012[5].
Attachment 1(a) to the 2012 RCAM Report	• A schedule providing details of the 2012[6] costs for each service, including EI's total loaded departmental cost, the total amount allocated to the primary service, the direct and common allocations to EGD and the direct and common allocations to other affiliates (Source: Appendix A to Schedule 2(b) of the ISA between EGD and EI dated January 1, 2011, the 2012 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)
Attachment 1(b) to the 2012 RCAM Report	• Four (4) accompanying schedules to Attachment 1(a) providing further details on 2012 costs: Primary Service Costs; General Expenses and Direct Charges; Return on Invested Capital; and EI's Support Services Cost (Source: Accompanying Schedules to Appendix A to Schedule 2(b) of the ISA between EGD and EI dated January 1, 2011, namely, the 2012 Regulatory Cost Allocation Methodology Confirmation Notice between EI and EGD)[7]

[5] The corresponding information for 2010 and 2011 was provided to the RCAM consultation group members in Attachment 1 to the 2011 RCAM Report dated January 31, 2012.
[6] The corresponding information for 2011 was provided to the consultation group members in Attachment 1(a) to the 2011 RCAM Report dated January 31, 2012.
[7] The corresponding information for 2011 was provided to the RCAM consultation group members in Attachment 1(b), to the 2011 RCAM Report dated January 31, 2012.

Document Description	Comments
Attachment 2 to the 2012 RCAM Report	• A table setting out the approved RCAM (departmental O & M) budgets for Enbridge Inc. by primary service for the years 2011 and 2012[8]
Attachment 3 to the 2012 RCAM Report	• 2012 versus 2011 RCAM Allocations Variance Analysis
Attachment 4 to the 2012 RCAM Report	• Continuity Statement of EI RCAM Budgets and Allocations to EGD for the period 2007-2012. Comprised of three schedules that updates for one additional year the 2007-2011 RCAM trend analysis provided to the intervenors in January 2012.
Attachment 5 to the 2012 RCAM Report	• A copy of the signed service schedules for 2012 for those individual services/general expenses & direct charges where the threshold for an individual service or general expenses & direct charges has been exceeded for 2012 (Source: Excerpt from Appendix "B" to Schedule 2(b) of the ISA dated January 1, 2011, the executed RCAM Confirmation Notice between EI and EGD for the year 2012).

Background Information:

- There have been no changes in methodology in the past year.
- The 2012 RCAM allocations to EGD have been determined using EI's approved RCAM budget for 2012 as the cost basis. This is consistent with the practice adopted, commencing with the calculation of the RCAM allocations to EGD for 2010, of using EI's current year's budget as the budget basis for determining RCAM allocations to EGD in any given year, rather than the previous practice of using EI's proxy budget (i.e., previous year's budget inflated) as the cost basis.
- EGD and EI have executed a confirmation notice to evidence the Parties' agreement to the cost allocations for 2012 (2012 RCAM Confirmation Notice), which has been incorporated into and forms part of the Intercorporate Services Agreement between EGD and EI dated January 1, 2011. The executed RCAM Confirmation Notice became Schedule 2(b) for 2012.
- Enbridge Inc.'s approved RCAM departmental budgets increased by $37.8 million or 15.9% to $276.2 million in 2012 from $238.4 million in 2011.[9]
- The aggregate threshold for 2012 in respect of RCAM cost allocations to EGD is 5.1%[10].
- The individual service threshold for 2012 is 12.1% and greater than $50,000.[11]

[8] The corresponding information for 2011 was provided to the RCAM consultation group members in Attachment 2 to the 2011 RCAM Report dated January 31, 2012.
[9] Please see Attachment 2 to this report for particulars.
[10] 2012 consensus forecast for Ontario all-items CPI of 2.1% per EGD's Economic & Market Analysis Group (Economic Outlook, Spring 2011) plus 3%.
[11] 2012 consensus forecast for Ontario all-items CPI of 2.1% per EGD's Economic & Market Analysis Group (Economic Outlook, Spring 2011) plus 10%

Aggregate Threshold:

- The aggregate corporate cost allocation amounts accepted by the Company for 2011 and 2012 were $26.7 million and $31.8 million, respectively.
- The overall nominal increase in 2012 was $5.1 million or 19.1%. Thus, the aggregate threshold of 5.1% for 2012 has been triggered. (On a normalized basis, the overall year-over-year increase would have been $3.6 million or 12.8% based on a comparison of the restated aggregate RCAM allocation amount for 2011 (of $28.2M)[12] with the accepted aggregate RCAM amount for 2012 of $31.8 million).
- The drivers for the increase in the overall RCAM cost allocation amount which contribute to the aggregate threshold being exceeded for 2012 are as follows:
    - A combination of a net increase in General Expenses and Direct Charges (i.e., arising from centrally managed programs) and an overall increase in Primary Service Charges, partially offset by a small reduction in the Return on Invested Capital, as summarized in the table below:

	Year-over-year Change (Increase/(Decrease)		**Year-over-year Change (Normalized)[13] Increase/(Decrease)**	
Primary Services	$2.2M	14.6%	$2.2M	14.6%
General Expenses & Direct Charges	$2.9M	25.4%	$1.4M	10.7%
Return on Invested Capital	$(0.0)M	(0.2)%	$(0.0)M	(0.2)%
Net Increase	**$5.1M**	**19.1%**	**$3.6M**	**12.8%**

    - As noted in the above table, General Expenses & Direct Charges are up net $2.9 million or 25.4%, principally due to increases in Directors Fees & Expenses, Insurance Premiums and EGD Stock Based Compensation Charges, partially offset by a combination of the following factors: the removal of Audit Fees from the RCAM commencing in 2012, a larger EFS credit and a small reduction in

[12] $26.7 million figure restated when accounting for the actual insurance premium cost for 2011 (as discussed at the January 31, 2012 RCAM Consultative meeting, plus $2.9M from $4.3M (budget estimate) to $7.2M (actual amount)) as well as accounting for the removal of Audit Fees from the RCAM commencing in 2012 (minus $1.4M) in order to effect an "apples-to-apples" comparison between 2011 and 2012.
[13] For illustration purposes only

depreciation expenses associated with the Risk Management System.

- The following table provides a breakdown of the SBC charge to EGD by SBC Category: Stock Options, Performance Stock Units (PSUs) and Restricted Stock Units (RSUs)

SBC Category[14]	2012 ($)	2011 ($)	Variance($)	Variance (%)
PSOPs	206,600	0	206,600	N/A
ISOPs	1,959,007	1,361,895	597,112	43.8%
PSUs	1,679,993	945,573	734,420	77.7%
RSUs	3,703,629	4,105,763	(402,134)	(9.8%)
Total	**7,549,229**	**6,413,231**	**1,135,998**	**17.7%**

Individual Service Threshold:

- The individual service threshold is triggered where the corporate cost allocation to any specific service or any direct charge increases in any one year by an amount greater than the CPI plus 10% and the increase is greater than $50,000.
- The individual service threshold for 2012 of 12.1% and an amount greater than $50,000 has been strictly triggered for the following fourteen (14) services and three (3) general & direct expense items:

  (a) Services (14)
  - Board of Directors Support – increase of 50.2% and $257.1K;
  - Business Development – increase of 38.1% and $203.2K;
  - Cash Management & Banking – increase of 23.7% and $92.2K;
  - Corporate Compliance – increase of 46.8% and $62.9K;
  - Employee Development – increase of 5% and $59.8K;
  - Enterprise IT Program Management – increase of 122.9% or $478.8K;
  - Enterprise IT Strategy Planning & Management – increase of 33.6% and $156.8K;
  - Financial and Project Accounting System Technical Support (Oracle) – increase of 34.6% and $90.6K;
  - HRIS Program Management and Development – increase of 38.7% and $839.3K;
  - Rate Regulated Entity Support – increase of 72.4% and $106.6K;

[14] There are four main Long Term Incentive Plan (LTIP) vehicles applicable at EGD in 2012: Performance Stock Option Plan (PSOP), Incentive Stock Option Plan (ISOP), Performance Stock Unit Plan (PSUP) and Restricted Stock Unit Plan (RSUP). Under the PSUP and RSUP, a number of phantom units are granted and paid out in cash at the end of the 3-year term (PSUs are granted to Vice President level and above, and RSUs are granted to Managers and Directors (and can be granted on a discretionary basis)). PSOP units were issued in 2012 (issued every 5 years).

- Records and Information Management – increase of 76.9% and $234.0K;
- Strategic Planning - increase of 29.2% and $74.0K;
- Total Compensation and Benefits – increase of 26.3% and $371.6K; and
- Portal Suite Operations & Technical Support – increase of 91.6% and $158.2K.

(b) General Expenses & Direct Charges (3)

- Directors Fees & Expenses – increase of 36.6% and $199.6K;
- Insurance Premiums - increase of 95.5% and $4.1M[15]; and
- EGD Stock Based Compensation Charge - increase of 17.7% and $1.1M.

- For the above-noted individual services and general expense & direct charges where the materiality threshold has been exceeded, a description of the drivers for the increase for the affected individual service, general expenses or direct charges are provided in Attachment 3 (2012 variance analysis, yellow highlighted areas)
- Attachment 3, the 2012 variance analysis schedule, also provides an explanation for the increase in the Investor Services Primary Service[16] because this service, while exhibiting an increase below the 12.1% trigger applicable from 2011 to 2012, experienced a dollar amount increase that exceeded the materiality threshold of $50K.

Service Update:

- As agreed**,** the Company is obliged to give the RCAM consultative notice of any service which is discontinued in its entirety, and to provide the consultative with a copy of the service schedule for any new service or direct charge which is undertaken or incurred in 2012 and beyond. In this connection, the Company confirms that in 2012:
  - While no service has been discontinued in its entirety[17], Audit Fees have been removed as they are no longer accounted for under the RCAM in order to better reflect the nature of the billing for this expense.[18]
  - While no new service or general expenses & direct charges has been undertaken or incurred, two insurance-related primary

[15] As noted in Attachment 3 to this report, the true variance is an increase of 18.0% and $1.3M on a normalized basis
[16] Increase of 8.9% and $72.4K
[17] Since 2007, the following Primary Services are not required by EGD: Aerial Pipeline Surveillance, External Communications, Gas Accounting, Gas Contract Accounting, Internal Employee Communications, Pension Plan Asset Management and Administration, Reservoir Engineering and Tax Advice.
[18] While the external auditor's fees are determined (centrally managed) by the Corporate Office, EGD pays the PwC bills directly.

services have been combined, namely Insurance Claims Support and Insurance Strategy and Management services, respectively.

MNP's Recommendations:

- As agreed, the Company is also obliged to provide the RCAM consultative with notice of its implementation of any of the recommendations made by Meyers Norris Penny LLP (MNP) in its final report dated February 28, 2007.
    - There have been no new major developments since the last report.
    - As part of the update study, MNP has reported on the status of those recommendations made in MNP's 2007 independent valuation of EGD's RCAM methodology.

VECC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Reference: Exhibit D1 Tab 4 Schedule 1 Attachment 1

a) Please update the Schedule to include 2012 and 2013.

RESPONSE

a) Please see attached (Exhibit D1, Tab 4, Schedule 2 Attachment 2, filed on June 1, 2012).

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

Enbridge RCAM Allocation Trend - 2007 To 2013

	Services / Direct Charges	2007 (As Approved by the OEB in EB-2006-0034)	2008 (As Approved by Enbridge under the ISA)	2009 (As Approved by Enbridge under the ISA)	2010 (As Approved by Enbridge under the ISA)	2011 (As Approved by Enbridge under the ISA)	2012 (As Approved by Enbridge under the ISA*)	2013 (As Proposed by Enbridge for Rate Recovery*)
Primary Services	2. Audit & Accounting Advice	$ 86,095	$ 80,559	$ 123,457	$ 176,276	$ 202,937	$ 91,270	$ 93,278
	3. Board of Directors Support	$ 511,270	$ 548,758	$ 524,382	$ 653,787	$ 512,237	$ 769,368	$ 785,892
	4. Business & Economic Financial Analysis	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	5. Business Development	$ 652,513	$ 648,678	$ 442,656	$ 440,041	$ 533,671	$ 736,918	$ 753,039
	6. Capital Market Financing & Access	$ 681,246	$ 704,394	$ 680,419	$ 857,868	$ 986,346	$ 1,020,173	$ 1,042,564
	7. Cash Management & Banking	$ 222,036	$ 228,425	$ 268,955	$ 346,810	$ 388,868	$ 481,073	$ 491,656
	8. Consolidation and Planning System Technical Support (Khalix)	$ 375,868	$ 411,470	$ 424,221	$ 492,550	$ 606,411	$ 245,089	$ 249,486
	9. Corporate Compliance	$ 99,725	$ 79,694	$ 103,385	$ 129,802	$ 134,323	$ 197,202	$ 201,540
	10. Industry Relations and Corporate Social Responsibility (CSR)	$ 245,307	$ 184,961	$ 310,317	$ 399,487	$ 465,205	$ 384,365	$ 392,741
	11. Emerging Energy Technology Research	$ 146,966	$ 73,533	$ 55,901	$ 74,371	$ 47,593	$ -	$ -
	12. Employee Development	$ 255,425	$ 326,279	$ 547,313	$ 803,140	$ 1,200,754	$ 1,260,568	$ 1,288,299
	13. Enterprise IT Program Management	$ 149,002	$ 198,557	$ 183,664	$ 413,230	$ 389,669	$ 868,494	$ 887,579
	14. Enterprise IT Strategy Planning & Management	$ 550,749	$ 534,684	$ 446,745	$ 594,422	$ 467,282	$ 624,115	$ 637,845
	15. Expense System Management & Technical Support (Oracle iExpense)	$ 119,526	$ 131,407	$ 147,714	$ 167,015	$ 239,394	$ 95,490	$ 97,384
	16. External Audit Coordination	$ 43,174	$ 42,501	$ 56,582	$ 76,248	$ 63,299	$ 103,399	$ 105,673
	18. Financial and Project Accounting System Technical Support (Oracle)	$ 320,766	$ 244,535	$ 256,641	$ 254,570	$ 261,570	$ 352,161	$ 358,097
	21. Gas Supply, Storage, and Transportation Strategy	$ 571,267	$ 525,390	$ 390,843	$ 231,134	$ -	$ -	$ -
	22. Government Relations	$ 119,234	$ 165,187	$ 47,715	$ 120,509	$ 34,848	$ 44,917	$ 45,895
	23. HRIS Management and Technical Support	$ 689,995	$ 802,393	$ 742,447	$ 1,545,942	$ 2,169,992	$ 3,009,273	$ 3,075,443
	24. Human Resource Advice	$ 101,190	$ 92,772	$ 168,134	$ 271,938	$ 354,073	$ 201,779	$ 206,184
	26. Insurance Claims Support, Strategy and Management (Combined)	$ 87,617	$ 75,291	$ 83,820	$ 127,227	$ 126,457	$ 108,240	$ 109,912
	28. Investor Services	$ 994,024	$ 843,304	$ 585,153	$ 685,330	$ 811,451	$ 883,837	$ 903,044
	29. Employee and Labour Relations (Combined)	$ 253,530	$ 299,985	$ 348,384	$ 458,995	$ 552,430	$ 478,201	$ 488,722
	30. Legal Advice	$ 303,414	$ 365,223	$ 433,306	$ 749,045	$ 572,710	$ 514,396	$ 525,600
	32. Planning, Management & Execution of Internal Audits	$ 82,338	$ 87,693	$ 187,727	$ 228,607	$ 185,494	$ 191,528	$ 195,741
	33. Rate Regulated Entity Support	$ 328,451	$ 225,379	$ 97,621	$ 128,419	$ 147,295	$ 253,904	$ 259,490
	34. Records and Information Management	$ 456,875	$ 623,795	$ 494,550	$ 298,336	$ 304,392	$ 538,352	$ 550,195
	36. Risk Assessment and Management	$ 541,913	$ 623,959	$ 686,348	$ 882,571	$ 1,062,095	$ 878,461	$ 897,681
	37. Strategic Planning	$ 167,834	$ 183,816	$ 160,673	$ 194,768	$ 253,879	$ 327,890	$ 335,020
	38. Supply Chain Management	$ 19,504	$ 9,394	$ 21,249	$ 24,088	$ 30,414	$ 39,706	$ 40,580
	40. Tax Reporting & Planning	$ 10,196	$ 13,238	$ 14,512	$ 21,630	$ 24,894	$ 55,308	$ 56,525
	41. Total Compensation and Benefits	$ 865,843	$ 887,721	$ 850,234	$ 1,313,100	$ 1,410,246	$ 1,781,809	$ 1,820,969
	43. Portal Suite Operations & Technical Support	$ 259,283	$ 263,057	$ 236,449	$ 156,062	$ 172,685	$ 330,881	$ 338,160
	Total Service Charges	**$ 10,312,177**	**$ 10,526,035**	**$ 10,121,518**	**$ 13,317,317**	**$ 14,712,914**	**$ 16,868,167**	**$ 17,234,234**
General Expenses & Direct Charges	Direct EFS Charge (Credit)	$ (453,946)	$ (461,261)	$ (213,789)	$ (1,174,981)	$ (1,150,894)	$ (2,314,784)	$ (2,314,784)
	Directors Fees & Expenses	$ 501,718	$ 475,364	$ 426,433	$ 517,905	$ 545,235	$ 744,819	$ 761,205
	Depreciation - Risk Management System	$ 24,512	$ 72,919	$ 74,436	$ 13,827	$ 68,965	$ 64,951	$ 64,951
	Insurance Premiums	$ 4,905,300	$ 4,096,200	$ 4,571,600	$ 5,179,873	$ 4,338,678	$ 8,483,868	$ 8,483,868
	Audit Fees	$ 808,955	$ 1,044,041	$ 1,248,118	$ 1,125,631	$ 1,369,832	$ -	$ -
	Enbridge Stock Based Compensation Charge	$ 1,663,249	$ 3,122,013	$ 4,262,039	$ 4,842,397	$ 6,413,231	$ 7,549,229	$ 7,715,312
	Total Direct Charges	**$ 7,449,788**	**$ 8,349,277**	**$ 10,368,836**	**$ 10,504,652**	**$ 11,585,047**	**$ 14,528,083**	**$ 14,710,552**
	Return on Invested Capital	**$ 300,553**	**$ 198,909**	**$ 625,604**	**$ 443,159**	**$ 369,543**	**$ 368,896**	**$ 357,703**
	Total Enbridge Allocation	**$ 18,062,517**	**$ 19,074,221**	**$ 21,115,958**	**$ 24,265,127**	**$ 26,667,504**	**$ 31,765,146**	**$ 32,302,489**

* Prior to proposed adjustment by MNP per MNP Final Report dated May 17, 2012, entitled: "Independent Evaluation of the 2013 Regulatory Cost Allocation Methodology Results"

Effective 2012, please note the following:

1. Two primary services have been combined, Insurance Claims Support and Insurance Strategy and Management.
2. Audit Fees **(Direct Charge) have** been removed, as **they are** no longer accounted for under **the** RCAM.

VECC INTERROGATORY #3

INTERROGATORY

D- Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Reference: Exhibit D1 Tab 24 Schedule 1

a) Please update the table on page 1.

RESPONSE

Please refer to Exhibit D1, Tab 24, Schedule 2, page 1 filed on May 31, 2012.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

VECC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Reference: RCAM Review-Exhibit D2 Tab 1, Schedule 1, Plus Appendix Section 11.2

a) Please provide a Schedule that includes the following:

Total RCAM amounts, Distribution Revenue Requirement(DRR), Utility O&M, Customers and Employees(FTE) 2007-2012

b) Please Benchmark Total RCAM amounts and Compound Annual Growth Rates (CAGR) to:

DRR
Utility O&M Costs
Customers and
Employees (FTE)
Calculate the CAGR for each 2007-2012

Please provide the Ratio of Stock-based Compensation Costs 2007-2013F to each of:

DRR
Utility O&M Costs
Customers and
Employees (FTE)

c) Calculate the CAGR for SBC.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

RESPONSE

a) See attachment 1

b) See attachments 1 and 2

c) See attachment 1

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

Attachment 1

	2007	2008	2009	2010	2011	2012	2013	CAGR (2007-2012)
RCAM Amount*	18,062,518	19,074,221	21,115,958	24,265,128	26,667,504	31,610,223	32,144,160	11.8%
Distribution Revenue Requirement (DRR)***	912,100,000	931,500,000	929,400,000	944,100,000	958,800,000	1,011,900,000	1,104,300,000	2.1%
Utility O&M**	326,784,000	323,446,000	336,986,000	346,746,000	360,511,000	402,344,000	438,127,000	4.2%
Customers	1,824,789	1,865,020	1,887,605	1,926,294	1,960,378	1,984,734	2,020,962	1.7%
Employees (FTE)	1,940	1,892	1,838	1,874	2,070	2,230	2,286	2.8%
EGD SBC	1,663,249	3,122,013	4,262,039	4,842,397	6,413,231	7,549,229	7,715,312	35.3%

* RCAM amounts for 2012 and 2013 reflect MNP's recommendations contained in its final report dated May 17, 2012 which the Company has accepted

** 2007-2011 represent actuals, 2012 estimate and 2013 budget

***2008 - 2012 Distribution Revenue Requirements were calculated using Board approved return on equity (ROE) percentages, excluding the 100 basis points allowed before earnings sharing is triggered.

Attachment 2

Ratio of SBC Costs 2007-2013 to Selected Items

	2007	2008	2009	2010	2011	2012	2013
Distribution Revenue Requirement (DRR)	0.2%	0.3%	0.5%	0.5%	0.7%	0.7%	0.7%
Utility O&M	0.5%	1.0%	1.3%	1.4%	1.8%	1.9%	1.8%
Customers	$ 0.9	$ 1.7	$ 2.3	$ 2.5	$ 3.3	$ 3.8	$ 3.8
Employees (FTE)	$ 857	$ 1,650	$ 2,319	$ 2,584	$ 3,098	$ 3,385	$ 3,375

VECC INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 5: Is the corporate cost allocation ("RCAM") appropriate?

Reference: RCAM Review-Exhibit D2 Tab 1 Schedule 1 Appendix Page 60 and Page 175

Preamble: MNP states that "Of the $7.3 Million Increase in Primary Services from 2007-2012 (as noted in the Table above) $5.4 million or 74% is attributed to services that MNP has categorized as IT and HR functions".

a) Please breakout the increased Services and Costs for IT and HR functions from 2007-2012 and calculate the CAGR for each.

b) Please indicate when the EI Service "HR Enterprise Business Solutions" (10089 $2 million) was initiated.

c) Confirm how much of the cost of this service was allocated to EGDI and the basis for this (cost driver etc) (Also see Appendix Page 60 ($770K)).

RESPONSE

a) Please see Attachment 1.

b) HR Enterprise Business Solutions was initiated in 2011.

c) $770,312 was the total amount allocated from the HR Enterprise Business Solutions Department (including support costs) with respect to the HRIS Program Management and Development Primary Service. The allocation factor used was Affiliate Headcount (AHC).

Witness: B. Yuzwa
S. Chhelavda
K. Culbert

IT and HR Functions per MNP's Categorization

2007 To 2012

Services / Direct Charges	2007	2008	2009	2010	2011	2012	CAGR
8. Consolidation and Planning System Technical Support (Khalix)	$ 375,868	$ 411,470	$ 424,221	$ 492,550	$ 606,411	$ 245,089	-8.2%
12. Employee Development	$ 255,425	$ 326,279	$ 547,313	$ 803,140	$ 1,200,754	$ 1,260,568	37.6%
13. Enterprise IT Program Management	$ 149,002	$ 198,557	$ 183,664	$ 413,230	$ 389,669	$ 868,494	42.3%
14. Enterprise IT Strategy Planning & Management	$ 550,749	$ 534,684	$ 446,745	$ 594,422	$ 467,282	$ 624,115	2.5%
15. Expense System Management & Technical Support (Oracle iExpense)	$ 119,526	$ 131,407	$ 147,714	$ 167,015	$ 239,394	$ 95,490	-4.4%
18. Financial and Project Accounting System Technical Support (Oracle)	$ 320,766	$ 244,535	$ 256,641	$ 254,570	$ 261,570	$ 352,161	1.9%
23. HRIS Program Management and Development	$ 689,995	$ 802,393	$ 742,447	$ 1,545,942	$ 2,169,992	$ 3,009,273	34.3%
24. Human Resource Advice	$ 101,190	$ 92,772	$ 168,134	$ 271,938	$ 354,073	$ 201,779	14.8%
42. Employee and Labour Relations (Combined)	$ 253,530	$ 299,985	$ 348,384	$ 458,995	$ 552,430	$ 478,201	13.5%
34. Records and Information Management	$ 456,875	$ 623,795	$ 494,550	$ 298,336	$ 304,392	$ 538,352	3.3%
41. Total Compensation and Benefits	$ 865,843	$ 887,721	$ 850,234	$ 1,313,100	$ 1,410,246	$ 1,781,809	15.5%
43. Portal Suite Operations & Technical Support	$ 259,283	$ 263,057	$ 236,449	$ 156,062	$ 172,685	$ 330,881	5.0%
Total IT and HR Functions	**$ 4,398,052**	**$ 4,816,656**	**$ 4,846,496**	**$ 6,769,301**	**$ 8,128,897**	**$ 9,786,212**	**17.3%**

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 6: Are the affiliate charges appropriate?

Reference: Exhibit A1 Tab 9 Schedule 1

a) Please provide a cost breakdown and service description of the $45.4 million to be paid to Enbridge Inc.

b) Indicate/Reconcile the response to the 2013 CAM and RCAM amounts.

c) Please provide a schedule showing amounts paid to Enbridge Inc from 2007-2013F using the breakdown in part a) and including CAM and RCAM amounts.

d) Please Provide a Summary schedule of services and costs from 2007-2013F and a Copy of the current SLAs for outbound EGDI Services to Gazifere Inc..

e) Confirm whether Enbridge corporate costs are charged directly to Gazifere or flow through EGD.

f) Provide a copy/extract of the most recent Regie Decision approving Affiliate Charges for Gazifere.

g) Summarize how costs for outbound Gazifere services are calculated and compare this to RCAM and CAM.

RESPONSE

a) See Attachment 1 for the cost breakdown. CAM methodology is based on EI's departmental budgets, in contrast to RCAM which is a service-based cost allocation methodology. Hence, there is no service description for CAM.

b) The 2012 and 2013 CAM amounts are set out at Attachment 1. The 2007 to 2013 RCAM amounts are set out at Attachment 2.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

c) The amounts paid under CAM are set out at Attachment 1 (2012 and 2013) and Attachment 3 (2007 to 2011). The breakdown of CAM amounts for 2007 to 2011 is presented on a different basis from 2012 to 2013, because actuals from previous years have been allocated to EGD departments, while the 2012 and 2013 forecast amounts are based on the EI departmental budgets. The cost breakdown for RCAM amounts for 2007 to 2013 is set out at Attachment 2.

d) See Attachment 4 for the summary schedule of services and costs for outbound EGD Services to Gazifere from 2007 to 2013F.

   See Attachment 5 for a copy of the current SLAs for outbound EGD Services to Gazifere Inc.

e) Enbridge corporate costs are directly charged to Gazifere.

f) See Attachment 6.

g) The costs for outbound Gazifere services are calculated using a methodology that is consistent with the requirements set out under the Affiliate Relationship Code ("ARC") for Gas Utilities. The manner in which CAM and RCAM are designed is described at Exhibit D1, Tab 4, Schedule 1, page 1.

Witnesses: B. Yuzwa
S. Chhelavda
K. Culbert

2012 and 2013 CAM

$Millions	2012 Budget	2013 Budget (2012 inflated by 2.01% except for insurance)
EI Department		
CEO	0.3	0.3
CIO	0.3	0.3
Corporate Aviation	0.5	0.5
Corporate IT Operations	0.5	0.5
IT Planning and Governance	1.1	1.1
CDM SYSTEMS	0.1	0.1
MRM SYSTEM	0.4	0.4
IAM SYSTEMS	0.4	0.4
EFS Support	(2.3)	(2.4)
Investor Relations	0.2	0.2
Treasury	0.2	0.2
CFO	0.1	0.1
Risk Control	0.3	0.3
Corporate Controller	1.5	1.5
Tax Services (Calgary)	0.0	0.1
Audit Services (Calgary)	0.2	0.2
Internal Controls	0.1	0.1
Corporate Secretarial	0.2	0.2
Corporate Admin.	0.3	0.3
Public Affairs & Corp. Comm.	2.2	2.2
Knowledge Management	0.8	0.8
Corporate Law	0.1	0.1
Records Management Law	0.1	0.1
HR Business Solutions Services	0.4	0.4
Organizational Effectiveness	0.5	0.5
Total Compensation	0.9	0.9
Corporate HR	0.8	0.8
HRIS Services	1.3	1.3
Strategic Development	0.4	0.4
Labour Relations	0.1	0.1
Group VP Corp. Resources	0.1	0.1
Risk Assessment	0.1	0.1
Corp. Climate Change	0.1	0.1
Total Department Expenses	**12.4**	**12.6**
General Expenses		
Directors Fees and Expenses	0.9	0.9
Corporate Law Legal Fees	0.1	0.1
Business Taxes	0.0	0.0
EI Rent & Leases	0.9	0.9
Industry Associations	0.0	0.0
Corporate Secretarial Legal Fees	0.2	0.2
Depreciation - Other Corporate	2.1	2.1
Depreciation - Risk Management System (50%)	0.1	0.1
Depreciation - EFS Assets	0.3	0.3
Audit Fees - EI fee distribution	0.2	0.2
EPI Charge	1.9	1.9
EGD Charge	0.3	0.3
EEP Charge (IT Shared Services)	0.6	0.6
Employee Benefits	2.8	2.8
EI Stock Based Compensation	5.2	5.3
Other Employee Benefits	1.7	1.7
Total General Expenses	**17.1**	**17.5**
Direct Charges:		
Insurance Premiums	8.5	8.2
Audit Fees	1.3	1.3
EGD Stock Based Compensation	7.5	7.7
Total Direct Expenses	**17.3**	**17.2**
Total	**46.8**	**47.2**
Total Enbridge Inc.	44.9	45.4
Total Enbridge Pipelines Inc.	1.9	1.9
Total	**46.8**	**47.2**

2007 - 2013 RCAM and CAM

	Services / General Expenses & Direct Charges	2007 ISA Approved by EGD	2008 ISA Approved by EGD	2009 ISA Approved by EGD	2010A ISA Approved by EGD	2011A ISA Approved by EGD	2012A ISA Approved by EGD	2013 F	2012A ISA Approved by EGD w/MNP adjustment	2013F w/MNP adjustment
	2. Audit & Accounting Advice	$ 86,095	$ 80,559	$ 123,457	$ 176,276	$ 202,937	$ 91,270	$ 93,278	$ 91,270	$ 93,278
	3. Board of Directors Support	$ 511,270	$ 548,758	$ 524,382	$ 653,787	$ 512,237	$ 769,368	$ 785,892	$ 769,368	$ 785,892
	4. Business & Economic Financial Analysis	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -
	5. Business Development	$ 652,513	$ 648,678	$ 442,656	$ 440,041	$ 533,671	$ 736,918	$ 753,039	$ 736,918	$ 753,039
	6. Capital Market Financing & Access	$ 681,246	$ 704,394	$ 680,419	$ 857,868	$ 986,346	$ 1,020,173	$ 1,042,564	$ 991,870	$ 1,013,640
	7. Cash Management & Banking	$ 222,036	$ 228,425	$ 268,955	$ 346,810	$ 388,868	$ 481,073	$ 491,656	$ 481,073	$ 491,656
	8. Consolidation and Planning System Technical Support (Khalix)	$ 375,868	$ 411,470	$ 424,221	$ 492,550	$ 606,411	$ 245,089	$ 249,486	$ 245,089	$ 249,486
	9. Corporate Compliance	$ 99,725	$ 79,694	$ 103,385	$ 129,802	$ 134,323	$ 197,202	$ 201,540	$ 197,202	$ 201,540
	10.Industry Relations & Corporate Social Responsibility (CSR)	$ 245,307	$ 184,961	$ 310,317	$ 399,487	$ 465,205	$ 384,365	$ 392,741	$ 384,365	$ 392,741
	11. Emerging Energy Technology Research	$ 146,966	$ 73,533	$ 55,901	$ 74,371	$ 47,593	$ -	$ -	$ -	$ -
	12. Employee Development	$ 255,425	$ 326,279	$ 547,313	$ 803,140	$ 1,200,754	$ 1,260,568	$ 1,288,299	$ 1,245,623	$ 1,273,025
	13. Enterprise IT Program Management	$ 149,002	$ 198,557	$ 183,664	$ 413,230	$ 389,669	$ 868,494	$ 887,579	$ 868,494	$ 887,579
	14. Enterprise IT Strategy Planning & Management	$ 550,749	$ 534,684	$ 446,745	$ 594,422	$ 467,282	$ 624,115	$ 637,845	$ 624,115	$ 637,845
	15. Expense System Management & Technical Support (Oracle iExpense)	$ 119,526	$ 131,407	$ 147,714	$ 167,015	$ 239,394	$ 95,490	$ 97,384	$ 95,490	$ 97,384
	16. External Audit Coordination	$ 43,174	$ 42,501	$ 56,582	$ 76,248	$ 63,299	$ 103,399	$ 105,673	$ 103,399	$ 105,673
	18. Financial and Project Accounting System Technical Support (Oracle)	$ 320,766	$ 244,535	$ 256,641	$ 254,570	$ 261,570	$ 352,161	$ 358,097	$ 352,161	$ 358,097
	21. Gas Supply, Storage, and Transportation Strategy	$ 571,268	$ 525,390	$ 390,843	$ 231,134	$ -	$ -	$ -	$ -	$ -
	22. Government Relations	$ 119,234	$ 165,187	$ 47,715	$ 120,509	$ 34,848	$ 44,917	$ 45,895	$ 44,917	$ 45,895
	23. HRIS Management and Technical Support	$ 689,995	$ 802,393	$ 742,447	$ 1,545,942	$ 2,169,992	$ 3,009,273	$ 3,075,443	$ 2,897,598	$ 2,961,312
	24. Human Resource Advice	$ 101,190	$ 92,772	$ 168,134	$ 271,938	$ 354,073	$ 201,779	$ 206,184	$ 201,779	$ 206,184
	25. Insurance Claims Support	$ 2,887	$ 5,602	$ 4,402	$ 6,301	$ 7,145		$ -	$ -	$ -
	26. Insurance Strategy and Management	$ 84,730	$ 69,689	$ 79,418	$ 120,927	$ 119,312	$ 108,240	$ 109,912	$ 108,240	$ 109,912
	28. Investor Services	$ 994,024	$ 843,304	$ 585,153	$ 685,330	$ 811,451	$ 883,837	$ 903,044	$ 883,837	$ 903,044
	29. Union Labour Relations + Employee Relations Strategy	$ 253,530	$ 299,985	$ 348,384	$ 458,995	$ 552,430	$ 478,201	$ 488,722	$ 478,201	$ 488,722
	30. Legal Advice	$ 303,414	$ 365,223	$ 433,306	$ 749,045	$ 572,710	$ 514,396	$ 525,600	$ 514,396	$ 525,600
	32. Planning, Management & Execution of Internal Audits	$ 82,338	$ 87,693	$ 187,727	$ 228,607	$ 185,494	$ 191,528	$ 195,741	$ 191,528	$ 195,741
	33. Rate Regulated Entity Support	$ 328,451	$ 225,379	$ 97,621	$ 128,419	$ 147,295	$ 253,904	$ 259,490	$ 253,904	$ 259,490
	34. Records and Information Management	$ 456,875	$ 623,795	$ 494,550	$ 298,336	$ 304,392	$ 538,352	$ 550,195	$ 538,352	$ 550,195
	36. Risk Assessment and Management	$ 541,913	$ 623,959	$ 686,348	$ 882,571	$ 1,062,095	$ 878,461	$ 897,681	$ 878,461	$ 897,681
	37. Strategic Planning	$ 167,834	$ 183,816	$ 160,673	$ 194,768	$ 253,879	$ 327,890	$ 335,020	$ 327,890	$ 335,020
	38. Supply Chain Management	$ 19,504	$ 9,394	$ 21,249	$ 24,088	$ 30,414	$ 39,706	$ 40,580	$ 39,706	$ 40,580
	40. Tax Reporting & Planning	$ 10,196	$ 13,238	$ 14,512	$ 21,630	$ 24,894	$ 55,308	$ 56,525	$ 55,308	$ 56,525
	41. Total Compensation and Benefits	$ 865,843	$ 887,721	$ 850,234	$ 1,313,100	$ 1,410,246	$ 1,781,809	$ 1,820,969	$ 1,781,809	$ 1,820,969
	43. Portal Suite Operations & Technical Support	$ 259,283	$ 263,057	$ 236,449	$ 156,062	$ 172,685	$ 330,881	$ 338,160	$ 330,881	$ 338,160
	RCAM Primary Services	**$ 10,312,177**	**$ 10,526,035**	**$ 10,121,518**	**$ 13,317,317**	**$ 14,712,914**	**$ 16,868,167**	**$ 17,234,234**	**$ 16,713,244**	**$ 17,075,905**
General Expenses & Direct Charges	Direct EFS Charge (budget true-up)	$ (453,946)	$ (461,261)	$ (213,789)	$ (1,174,981)	$ (1,150,894)	$ (2,314,784)	$ (2,314,784)	$ (2,314,784)	$ (2,314,784)
	Directors Fees & Expenses (same as CAM)	$ 501,718	$ 475,364	$ 426,433	$ 517,905	$ 545,235	$ 744,819	$ 761,205	$ 744,819	$ 761,205
	Risk Management System (same as CAM)	$ 24,512	$ 72,919	$ 74,436	$ 13,827	$ 68,965	$ 64,951	$ 64,951	$ 64,951	$ 64,951
	Insurance Premiums (same as CAM)	$ 4,905,300	$ 4,096,200	$ 4,571,600	$ 5,179,873	$ 4,338,678	$ 8,483,868	$ 8,483,868	$ 8,483,868	$ 8,483,868
	Audit Fees (same as CAM)	$ 808,955	$ 1,044,041	$ 1,248,118	$ 1,125,631	$ 1,369,832	$ -	$ -	$ -	$ -
	BU Stock Based Compensation Charge (only EGD)	$ 1,663,249	$ 3,122,013	$ 4,262,039	$ 4,842,397	$ 6,413,231	$ 7,549,229	$ 7,715,312	$ 7,549,229	$ 7,715,312
	RCAM General & Direct Charges	**$ 7,449,788**	**$ 8,349,277**	**$ 10,368,836**	**$ 10,504,652**	**$ 11,585,047**	**$ 14,528,083**	**$ 14,710,552**	**$ 14,528,083**	**$ 14,710,552**
	Rate of Return	**$ 300,553**	**$ 198,909**	**$ 625,604**	**$ 443,159**	**$ 369,543**	**$ 368,896**	**$ 357,703**	**$ 368,896**	**$ 357,703**
	Total RCAM Allocation	**$ 18,062,518**	**$ 19,074,221**	**$ 21,115,958**	**$ 24,265,128**	**$ 26,667,504**	**$ 31,765,146**	**$ 32,302,489**	**$ 31,610,223**	**$ 32,144,160**
	Total CAM Allocation	**$ 27,713,268**	**$ 32,166,463**	**$ 34,266,680**	**$ 36,693,265**	**$ 43,439,942**	**$ 46,815,705**	**$ 47,268,238**	**$ 46,815,705**	**$ 47,268,238**

Note: For CAM, 2007-2011 figures represent Actuals, 2012 represents Estimate and 2013 represents Budget

2007 - 2011 CAM

EGD Department	**2011** Actual	**2010** Actual	**2009** Actual	**2008** Actual	**2007** Actual
Finance					
FIXED INTERNAL CHARGES	$1.7M	$2.0M	$1.7M	$1.7M	$2.0M
GENERAL EXPENSE ALLOCATIONS	$.1M	$.0M	$.0M	$.0M	$.0M
	$1.8M	$2.0M	$1.7M	$1.7M	$2.0M
Legal					
FIXED INTERNAL CHARGES	$.8M	$.8M	$.3M	$.3M	$.4M
GENERAL EXPENSE ALLOCATIONS	$1.0M	$1.0M	$1.0M	$1.1M	$1.2M
	$1.8M	$1.8M	$1.3M	$1.4M	$1.6M
Information Services					
FIXED INTERNAL CHARGES	$2.6M	$2.1M	$2.9M	$2.4M	$2.0M
GENERAL EXPENSE ALLOCATIONS	$.4M	$.0M	$.0M	$.0M	$.0M
	$3.0M	$2.1M	$2.9M	$2.4M	$2.0M
BDCS					
FIXED INTERNAL CHARGES	$.1M	$.2M	$.1M	$.0M	$.0M
GENERAL EXPENSE ALLOCATIONS	$.0M	$.0M	$.0M	$.0M	$.0M
	$.1M	$.2M	$.1M	$.0M	$.0M
HR					
STOCK BASED COMPENSATION	$7.5M	$5.6M	$4.9M	$4.3M	$2.3M
FIXED INTERNAL CHARGES	$10.1M	$7.6M	$6.0M	$5.1M	$3.2M
GENERAL EXPENSE ALLOCATIONS	$2.5M	$3.8M	$3.7M	$3.8M	$3.7M
	$20.1M	$17.0M	$14.6M	$13.3M	$9.2M
Engineering					
INSURANCE PREMIUMS	$7.2M	$5.2M	$4.9M	$4.5M	$4.5M
FIXED INTERNAL CHARGES	$.3M	$.3M	$.1M	$.0M	$.0M
GENERAL EXPENSE ALLOCATIONS	$.1M	$.0M	$.0M	$.0M	$.0M
	$7.6M	$5.5M	$5.0M	$4.5M	$4.5M
P&GA					
FIXED INTERNAL CHARGES	$2.0M	$1.7M	$1.4M	$1.3M	$1.2M
GENERAL EXPENSE ALLOCATIONS	$.0M	$.0M	$.0M	$.0M	$.0M
	$2.0M	$1.7M	$1.4M	$1.3M	$1.2M
Corporate					
FIXED INTERNAL CHARGES	$5.9M	$3.1M	$4.1M	$4.3M	$4.5M
GENERAL EXPENSE ALLOCATIONS	$1.2M	$3.4M	$3.1M	$3.2M	$2.7M
	$7.1M	$6.5M	$7.2M	$7.6M	$7.2M
Total	**$43.4M**	**$36.7M**	**$34.3M**	**$32.2M**	**$27.7M**

Gazifere Summary of Costs (from EGD)
2007-2013F

	2007	2008	2009	2010	2011	2012*	2013*
Transfer of receipts	(18,734.41)	(16,701.70)	(8,233.47)	0.00	0.00	N/A	N/A
Labour JV84 C&M	(7,931.52)	0.00	143,478.34	429,954.79	460,816.21	N/A	N/A
Miscellaneous	69,102.64	4,689.93	1,190.58	244,876.13	(383,859.01)	N/A	N/A
Management Fees - Operations	111,591.19	182,371.31	248,212.63	209,671.16	109,430.77	N/A	N/A
Information Services Management Fee	320,047.62	359,878.68	349,098.19	448,390.36	455,101.74	N/A	N/A
Fleet Charges	114,158.26	128,875.63	95,682.95	102,491.21	135,280.62	N/A	N/A
H.W.E. & Tools Maintenance	11,388.11	13,272.78	14,651.36	21,283.30	14,721.30	N/A	N/A
Financial Studies Department Expenses	57,763.32	117,683.60	31,115.52	94,448.90	75,914.30	N/A	N/A
Computer Equipment	305,911.00	0.00	73,843.68	154,391.00	2,450.72	N/A	N/A
Employee Benefits	137,641.20	102,227.63	83,001.47	126,932.55	128,262.91	N/A	N/A
Legal Services	6,675.00	4,175.00	0.00	2,085.00	4,594.00	N/A	N/A
Consumers Gas Management Fees	164,896.40	282,646.29	279,005.48	328,504.32	273,589.63	N/A	N/A
CIS Charges	72,454.08	682,758.98	1,425,898.28	313,350.52	94,560.89	N/A	N/A
Gas Cost	43,947,854.15	43,838,454.28	37,237,111.73	25,965,471.71	23,814,289.98	N/A	N/A
Gas Cost Adjustment	744,233.31	(806,224.67)	9,633.00	0.00	(3,785.26)	N/A	N/A
TOTAL	**46,037,050.35**	**44,894,107.74**	**39,983,689.74**	**28,441,850.95**	**25,181,368.80**	**26,909,625.00**	**25,259,858.00**

* 2012 and 2013 represent preliminary numbers

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D6
Schedule 20.1
Attachment 4
Page 1 of 1

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the Agreement")

1. PREFACE

This Schedule is intended to identify ***Application Hosting and Maintenance Services*** to be provided to Gazifère Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc. (the "Services Provider").

2. TERM

The services defined in this Schedule are to be provided to the Services Recipient for a period of thirty-six [36] months commencing January 1, 2011 and terminating December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

3. APPLICATION HOSTING SERVICES

Services Provider will provide *Application Hosting and Maintenance Services* to Services Recipient. This Schedule describes the stakeholders, objectives, scope, service levels, constraints and client responsibilities for this assignment.

4. STAKEHOLDERS

The stakeholders relating to this Schedule are:

Role	Name	Title	Contact Numbers
Services Recipient	Jean-Marie Dallaire	IT Lead/Co-ordinator	Office (819) 771-8321 ext 2155 jean-marie.dallaire@gazifere.com
Services Provider	Joy McDonnell-Soda	Manager, IT Enterprise Services	Office (416) 495-6143 Joy.Mcdonnell-Soda@enbridge.com

5. SCOPE

Services Provider will provide Application Hosting and Maintenance Services to Services Recipient. These services consist of:

1. General Service
2. UNIX Server Support
3. Application Support

5.1 General Service

Services Provider will:

- Assume responsibility for the operation and management of services to host the Applications listed in Appendix "A" for Services Recipient
- Provide service delivery management accountable for all aspects of Service Delivery.
- Meet or exceed all service levels as defined in Article 6 Service Levels.

5.2 UNIX Server Support

Services Provider will provide UNIX Server support 7X24 for the UNIX servers listed in Appendix "A" that consists of:

- A facility to host equipment, providing power, air conditioning, raised floor, network connections, and secured access for the UNIX servers listed in Appendix "A".
- Daily operation and administration of the backup and recovery of application and data stored on the Unix servers listed in Appendix "A"
- The maintenance and support of the application and hardware which perform the backups;
- Offsite tape vaulting and storage of the backed up information;
- Tier 2 support pertaining to Unix environment
- Problem and change management for Unix hardware and operating system.
- Security compliance and administration
- Technical support for hardware and operating systems
- Batch Processing, scheduling, monitoring and restarts
- Unix system administration, storage management, hardware configuration, tuning, and capacity planning
- Performance of system maintenance functions during the maintenance windows.

5.3 Application Support

Services Provider will provide Application Support Services that will consist of:

a) Support Analysts that will consist of:

- Providing service between the hours of 8:30 a.m. and 5:00 p.m. Eastern time Monday to Friday excepting Services Provider holidays.
- The engagement of support analysts to support the application listed in Appendix "A" as required by Services Recipient.
- Support activities are limited to monitoring, maintenance, break fix, corrective changes, adaptive changes, administration, and user support.
- For purposes of the third bullet point in this Section 5.4, the term "Monitoring" means the timely examination of the application and its attached data to ensure proper performance to achieve the service levels as defined in Article 6 Service Levels
- For purposes of the third bullet point in this Section 5.4, the term "Maintenance" means any activity that occurs on a regular basis or as result of monitoring that results in modification of the application environment as to maintain or enhance the application's performance.
- For purposes of the third bullet point in this Section 5.4, the term "Break fix" means the modification of an application environment initiated by some problem such that the application environment performs as prior to the problem.
- For purposes of the third bullet point in this Section 5.4, the term "Corrective change" means the modification of the application environment to permanently enhance the performance of the application environment beyond historical performance.
- For purposes of the third bullet point in this Section 5.4, the term "Adaptive change" means the modification of an application environment to permanently alter its functionality.
- For purposes of the third bullet point in this Section 5.4, the term "Administration" means the routine activities that are associated with an application performed through special routines provided by the application for such administrative purposes. This may include activities such as defining new users or security profiles.

- For purposes of the third bullet point in this Section 5.4, the term "User support" means the provision of advise or information to assist the user in their use of the application and any training required to maintain such analysts level of expertise in the support of such application.

b) After Hours Support that will consist of:

- On call assignment of a number of support analysts to cover the on call requirements as detailed in Appendix "A"
- The provision of break fix support between the hours of 5:00 p.m. and 8:30 a.m. Eastern time Monday to Thursday and Services Provider holidays and 5:00 p.m. Fridays and 8:30 a.m. Mondays Eastern time.

c) Infrastructure Upgrades that will consist of:

- The installation of new versions of the application, their underlying Application Infrastructure designated in Appendix "A"

6. SERVICE LEVELS

Activity	Service Level	Attainment (Measured Monthly)
Response to pager calls	96%	Percentage of calls responded to within 30 minutes of initial page.
Batch Job Execution	99.7%	% if batch jobs that execute as scheduled
Unix Server Availability	99.7%	% of time Unix Servers are available
Database Availability	99.7%	% of time Databases are available

Note: This Services Levels exclude scheduled outages.

7. CONSTRAINTS

The constraints around this Schedule are listed below:

1. This agreement reflects the shared usage of application with Services Provider. The support and usage of the application will be terminated upondecommissioning of any application listed in Appendix A. At such time, pricing will be adjusted accordingly.
2. Direction and priorities of Services Provider staff assignment to tasks are to be provided by Services Provider Service Delivery Manager through out the term of this engagement.
3. Until such time as the parties have developed formal acceptance criteria and procedure for any services or deliverables provided hereunder, any services and deliverables provided hereunder shall be deemed to be accepted by Services Recipient if Services Recipient has not provided notice to Services Provider within 10 business days of receipt of the applicable service or deliverable.

8. SERVICES RECIPIENT RESPONSIBILITIES

The following list represents Services Recipient responsibilities associated with this agreement:

1. Introductions and orientation to Services Recipient staff as appropriate;
2. Maintenance of contact information in Services Provider Help Desk support system.

9. OUT OF OR BEYOND SCOPE SERVICES

The following services shall not be considered a part of this Schedule:

- Training fees and classroom rental.
- Training of Services Recipient employees.
- Adaptive and corrective changes where such changes are restricted to a 3rd party supplier provided however that Services Provider will use commercially reasonable efforts to have any such 3rd party supplier(s) make changes deemed necessary by Services Recipient, acting reasonably.

10. PRICING AND CONDITIONS

The services described in this Schedule shall be charged at a per unit basis as detailed in Appendix "A". The 2011 rate will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.

The estimated fees for services described in this Schedule shall be $111,943 in 2011. The foregoing is based on an annual calendar year forecast of expected service requirements reasonably determined by the Services Provider. The Services Provider reserves the right to revise this estimate in the event that the services rendered are significantly more or less than the estimated amount. The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately and agreed upon in advance with the Services Recipient.

Payment for services rendered is due in accordance with the schedule set out in the Agreement.

Dated this 11th **day of** May, 2011

ENBRIDGE GAS DISTRIBUTION INC.	**GAZIFÈRE INC.**
Per:	Per:
Name: Narin Kishinchandani	Name: Jamil LeBlanc
Title: Vice President, Finance	Title: General Manager
Per:	Per:
Name: Mark R. Boyce	Name: Lise Mauviel
Title: Vice President, Law & Information Technology	Title: Manager Regulatory Affairs + Budgets

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Appendix A

Application Hosting and Maintenance Hosting Monthly Service Charges

Application Name	System Type	Description	Basis of Allocation	Monthly Charge	Annual Charges	Portion of Application Services Cost
EnMar (Lodestar)	UNIX	Provides meter management capabilities.	Number of meters managed as a % of the total.	$271	$3,252	0.15%
Gazifère Contract Management	UNIX / Web	Replacement for GasCon. Contract Management system.	Dedicated Gazifère system.	$831	$9,972	100%
Various Others, EQAT, MSDS Historical Data Access (ORM data), etc.	Various	Provide access to database(s)	Number of Services Recipient users as % of total.	$115	$1,375	3%
UCIR	UNIX	Unified Customer Information Reporting, provides conduit of Gazifère billing data to downstream systems	Amount of support team hours per month, plus software maintenance. Fees.	$8,112	$97,344	100%
Total					**$111,943**	

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the Agreement")

1. PREFACE

This Schedule is intended to identify ***Application Operations Services*** for the Work and Asset Management Solution (entitled the "EnVision" application) to be provided to Gazifère Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc. (the "Services Provider") under agreement with the Application Services Provider (ASP), Accenture Inc. (the "ASP") .

2. TERM

The services defined in this Schedule are to be provided to the Services Recipient for a period of thirty-six [36] months commencing January 1, 2011 and terminating December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

3. APPLICATION OPERATIONS SERVICES

Services Provider will provide *Application Operations Services* to Services Recipient. This Schedule describes the stakeholders, objectives, scope, service levels, constraints and client responsibilities for this assignment.

4. STAKEHOLDERS

The stakeholders relating to this Schedule are:

Role	Name	Title	Contact Numbers
Services Recipient	Jamie Leblanc	General Manager	Office (819) 771-8321 ext. 2310 Jamie.leblanc@gazifere.com
Services Provider	Joy McDonnell-Soda	Manager, Enterprise Services	Office (416) 495-6143 Joy.McDonnell-Soda@enbridge.com

5. SCOPE

The EnVision application is a shared solution utilized by both the Services Provider and Services Recipient. The Services Provider has outsourced the hosting and maintenance of the EnVision solution to Accenture Inc. operating as the Application Services Provider (ASP). Services Provider will manage ASP to provide Application Operations Services for the EnVision application to Services Recipient, under agreement with the ASP. These services consist of:

1. Service Management – the day-to-day function of managing and integrating end-to-end service delivery
2. Application Management - support, maintenance, and enhancement of the Application.
3. Technology Operations - provides the Data Centre, technology support, hardware and software infrastructure to operate and maintain the required level of performance, security and availability of the Envision Application.

5.1 Service Management

Services Provider will:

- Assume responsibility for overseeing the day-to-day operation and management of services to host the EnVision Application for Services Recipient.
- Manage communications among Services Recipient, Services Provider, ASP and any third parties involved in the provision of services.
- Provide service delivery management accountable for all aspects of Service Delivery.
- Provide tracking, measuring and reporting of service performance as provided by ASP.
- Meet or exceed all service levels as defined in Appendix 'A' – Service Levels.
- On an annual basis, Services Recipient and Services Provider will meet to review overall service performance, review Services Recipient strategic direction, and agree to potential service adjustment, if any.

5.2 Application Management

Services Provider will manage ASP to provide for the support, operation, maintenance and enhancement of the application in a method and manner by which the Services Provider's obligations under the SLA are achieved. Application Management Services will consist of:

- **Application Support:** Providing service between the hours of 8:00 a.m. and 5:00 p.m. Eastern time Monday to Friday excepting Services Provider holidays. Not withstanding the above, Services Providers Help Desk and will be available 24-hours a day, 7 days a week, 365 days per year.
- **Problem Fixes:** A Problem is defined as a system behavior that does not conform to the system specifications regarding availability, processing, or functionality. Services Recipient Users will directly contact the Services Provider Help Desk for assistance. The Help Desk will log the call, gather preliminary information, perform general Problem diagnosis, were applicable provide Problem resolution, and answer general inquiries. Each identified Problem not resolved at the Help Desk will be assigned a Problem Category and escalated for further diagnosis and resolution. When an Application Problem has been identified, Services Provider will manage ASP to seek to return the Application to working order based upon the criticality of the incident. Services Provider will manage expectations of Users regarding resolution time for Problems, by updating trouble tickets and contacting Users and /or Services Recipient stakeholder. Services Provider will manage ASP to provide reasonable notice to Services Recipient of anticipated Problems based on Problem and performance trend analysis.
- **Ad-Hoc Requests:** Services Recipient may initiate Ad-Hoc Request by contacting the Services Providers Help Desk.
- **Product Enhancements:** Services Recipient will direct all Product Enhancement requests to the appropriate Business Lead. The Business Lead will evaluate the request and if approved will enter the request into the Services Providers Request Management Tool.
- **Application Maintenance:** Services Provider will manage ASP to monitor on a regular basis the applications performance, and the impact of any modifications to the application or the application environment. Monitored results will be analyzed and recommendations for change identified.
- **Product Upgrades:** Upgrades to Applications will be reviewed by Services Provider, ASP and Services Recipient and implemented on an agreed schedule following the operational change control process. ASP will enter

into and maintain maintenance agreements for all hardware and software products required to provide Application Operations Services.

- **Database Administration Support:** Services Provider will manage and administer the Databases used in support of the EnVision application. Database Administration Support will include:
    - Structural monitoring and maintenance
    - Performance monitoring and maintenance
    - Tuning
    - Database security
    - Database upgrade/patches/fixes management
    - Database backup & recovery management
    - Troubleshooting and Problem determination
    - Scripting
    - Data moves and copies between environments (including subsets, e.g. subset of production to training)
    - Database modeling for specific changes
    - Database capacity planning
- **Release Management:** The release management activity includes the release of changes (emergencies, batched changes, releases of in-scope new functionality or fixes). On an ongoing basis, the release schedule for non-emergency changes (e.g. Discretionary and Major Enhancements) will be mutually agreed by Services Provider, Services Recipient and ASP. Over time, the objective will be for scheduled releases to be no more frequent than quarterly. A release is a set of software changes packaged together with a common release date. The purpose of a release is to provide greater control, gain efficiencies and improve the quality of the implemented changes.
- **Training:** Services Provider will manage ASP in cooperation with Services Recipient ensure that training materials and training techniques are provided to designated trainers to the extent required to support enhancements to the system. Services Recipient will be responsible for coordinating training to coincide with packaged releases of the software.

5.3 Technology Operations

Services Provider will manage the ASP to provide the necessary operating systems, databases, integration support and network support to manage and maintain the application infrastructure in a method and manner by which the Services Provider's obligations under the SLA are achieved. Technology Operations Services will consist of:

- **Technical Support:** Provide the necessary operating system, database integration, and network support skills to manage and maintain the EnVision Application
- **Event detection and notification:** provide proactive continuous monitoring of the operating systems, databases, applications (if available) and covered network components, 24 hours a day, 7 days a week. Monitor computing environment resources for availability and predefined thresholds on a daily basis.
- **Notification and Escalation Management:** Services Providers Level 1 Help Desk will be notified of any service disruption events and escalate both calls and events based on the agreed notification and escalation procedures to Service Recipients staff.
- **Database and File System Backup and Restore Operation:** Database and File System backups will be scheduled to ensure both data integrity and secure data storage. Two types of backups are performed on a nightly basis: incremental disk

backups and incremental database backups. Incremental backups are cumulative back to the last full backup. Backups will be taken of each disk on each server in addition to the Storage Area Network. Full backups are typically taken every Sunday, but in any event, not less than weekly. Periodic backup/restore tests will be performed to ensure the functional integrity of backups.

- **Media Management:** Provide for the transportation of backup media to a location remote from the server. Perform on site & off site tape librarian activities for all backup media. Data backups are stored to tape in the tape library. Daily incremental backups (data and disk) are transferred the next day to a separate location. Ad hoc requests for file restoration will be completed in 24 hours.
- **Production Job Scheduling:** Administer and maintain a list of recurring tasks within the automated scheduling tools provided by the operating system. This includes the addition/modification/deletion of jobs to the list as well as ensuring that those items presently in the list are executed as scheduled.
- **Physical Site Security:** Maintain a secure Data Centre environment with personnel access limited to a "need to" basis.
- **System and Application Security:** Data Security and integrity management. Provision of Firewall to protect against external data network gateway access and overall network security management. Virus prevention management. The security services include the regular collection, correlation and analysis of security data to identify, isolate and notify of potential security threats.
- **User Administration:** Provide facilities and procedures to coordinate the administration, setup and maintenance of User accounts for application, server, and database level security.
- **Routine and Exception Maintenance Windows:** Perform routine daily maintenance while supporting normal EnVision application processing and operations. A daily window between 2:00am and 4:00am (ET) for system maintenance will be defined to be used on an as needed basis. On a weekly basis a four-hour downtime window will be available for performing preventative routine maintenance activities (typically on Sunday 1:00am to 5:00am).
- **System Fault Isolation and Resolution:** When a problematic event has been detected, Services Provider will seek to return a malfunctioning resource to working order and /or prevent it from failing again.
- **System Preventative Maintenance:** Coordinate and execute maintenance tasks in the computing environment with the goal of preventing unexpected downtime of infrastructure resources.
- **Performance Trend Analysis:** Analyze resource utilization information to understand how resources are performing, being utilized and how the use of these resources can be optimized.
- **Disaster Recovery:** Provide Disaster Recovery services in the event of a Disaster event occurring in the EnVision Application hosting Data Center. A Disaster event is an event that has occurred or will occur that would cause the system to be unavailable for a period greater than 48 hours. Partial read only functionality and service level recovery will occur within 48 hours of the Disaster event. At a minimum, full functionality will be restored within one calendar week.

goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately and agreed upon in advance with the Services Recipient.

Payment for services rendered is due in accordance with the schedule set out in the Agreement.

Dated this 11th **day of** May, 2011

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____

Name: Narin Kishinchandani
Title: Vice President, Finance

Per: _____

Name: Mark R. Boyce
Title: Vice President, Law & Information Technology

GAZIFÈRE INC.

Per: _____

Name: Jamie LeBlanc
Title: General manager

Per: _____

Name: Lise Manuel
Title: Manager Regulatory Affairs & Budgets

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Appendix "A" – Application Operations Services Schedule between Enbridge Gas Distribution Inc. and Gazifère Inc.
Service Levels

Service Measure	% Weight	Measurement	Annual target
1. Periodic Batch Job / Interface / Report Execution	2%	% Run as scheduled	99-99.7%
2. Real Time Jobs	2%	% Run as scheduled	99-99.7%
3. Request for special on demand Batch Job / Interface / Reports	2%	% where schedule to run is established within 2 hours of request	98%
4. System Availability for EnVision	10%	% time available	99-99.5%
5. System Performance Measure	9%	TBD – Use Performance Monitoring Tool to measure compliance	TBD
6. Number of Outages	9%	The number of critical application outages	3
7. Resolution to Category 1 (CRITICAL) outage	9%	% of critical outages resolved within 2 business hours	98%
8. Resolution to Category 2 (MAJOR) outages	2%	% of major outages resolved within 4 business hours	98%
9. Resolution to Category 3 (MINOR) outages	2%	% of minor outages resolved within 8 business hours	98%
10. Response to Category 1 (CRITICAL) and Category 2 (MAJOR) Problems	4%	% of satisfactory response and resolution strategies delivered within 2 hours	98%
11. Communication of Category 1 (CRITICAL) and Category 2 (MAJOR) problems to Primary Enbridge Support (PES)	3%	% of satisfactory responses delivered to PES (Measured only where Help Desk ticket assignment is not resolved in 30 minutes)	98%
12. Resolution to Category 1 (CRITICAL)	5%	% of satisfactory workarounds or resolutions delivered within 24 hours	98%

Appendix "A" – Application Operations Services Schedule between Enbridge Gas Distribution Inc. and Gazifère Inc.

Service Levels

Service Measure	% Weight	Measurement	Annual target
13. Response to Category 2 (MAJOR) Problems	2%	% of satisfactory workarounds or resolutions delivered within 72 hours	98%
14. Resolution to Category 3 (MINOR) Problems	2%	% satisfactorily resolved within the next maintenance release (except for those with less than 14 days notice)	98%
15. Questions, Ad-hoc and high level estimation requests	0%	% Requests satisfactorily responded to within 2 Business Days	95%
16. High Level estimation requests	7%	Accenture will provide 4 HLE's for 4 RMT's within 5 business days 100% of the time	95%
17. Requests for Enhancements	15%	% delivered on time and according to specifications	85%
18. Break/Fix RMT delivery measure	15%	% delivered on time and according to specifications	85%
	100%		

Note: This Services Levels exclude scheduled outages.

Appendix "B"
Application Operations Services Monthly Service Charges

Application Name	On Call Window	System Type	Description	Basis of Allocation	Monthly Charge	Annual Charges	Portion of Application Services Cost
EnVision	24/7	UNIX	Provides access to asset management database.	Measure of Services Recipient Pipeline in their system.	$12,575	$150,900	2.7%
Total					**$12,575**	**$150,900**	

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Audit Services*** to be provided to Gazifère Inc. (the "Services Recipient") by Enbridge Gas Distribution (the "Services Provider").

The services defined in this Schedule are to be provided to the Services Recipient for a period of three years, commencing January 1, 2011 and ending December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to use a systematic and disciplined approach to independently evaluate and recommend improvements to the effectiveness of the Service Recipient's risk management, control and governance processes.

The Services Provider will develop an overall Audit plan in consultation with Senior Management and based upon an assessment of Corporate risks. However, the scope of the Services Provider work will be unrestricted to ensure that no limitations are imposed on its objectivity in the selection of areas to be examined or in the final evaluation of those areas.

During the time period covered by the audit plan, modifications may occur due to reprioritization, resource constraints or additional governance review and audit requirements identified by Services Recipient management, the Services Provider or other senior management within Enbridge Inc.

The detailed planning for individual reviews and audits will be performed prior to commencement of fieldwork and will include a review of the planned scope, objectives and timeframe with Services Recipient management.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider is responsible for the following:

- Consult with management of the Services Recipient prior to finalization of the overall audit plan to ensure that the significant risk areas of the Services Recipient will be adequately addressed. Subsequently, if modification to the audit plan is required, have on-going discussions with management to ensure all significant risk areas continue to be adequately addressed;
- Liaise with the responsible Audit, Finance & Risk Committee;
- Review the requests for additional audit requirements and/or consulting services advise as to whether or not it is able to or should take action to address within one week of receiving sufficient information to assess the related scope, objectives, timing, and resources required;
- Work with the Services Recipient in finalizing the detailed scope, objectives and timing for individual reviews and audits to ensure management's concerns are appropriately addressed and least possible disruption to operations will result;
- Ensure all reviews and audits are performed and the related reports prepared by a person or persons having adequate technical training and proficiency in auditing, with due care and with an objective state of mind;

- Issue a draft audit report to management that summarizes the significant governance review and audit findings and recommended courses of action within a reasonable period after the completion of field work; and

- Report to the responsible Audit, Finance and Risk Committee on significant results of its reviews and audits of the Services Recipient and other audit related reporting requirements. Ensure the Services Recipient reviews related information and that comments are incorporated as appropriate. Advise the Services Recipient of associated deadlines and provide as reasonable a turnaround time as possible.

The Services Recipient is responsible for the following:

- Authorize the Services Provider to have full and free access to all Corporate functions, records, property and personnel required to fulfill its responsibilities;

- Make available the necessary and appropriate level of resources on a timely basis and fully disclose and accurately represent the required information to allow the detailed planning and execution of audits to occur;

- Have senior management, including the President and other staff members as appropriate, meet with the Services Provider to ensure that the governance review and audit plan continues to adequately address significant risk areas;

- Review and provide comments on the reports to the Audit, Finance and Risk Committee prepared by the Services Provider relating to the Services Recipient to meet the associated deadlines; and

- Provide responses to governance review and audit findings for inclusion in a governance review and audit report within agreed timing of receiving the draft governance review and audit report from the Services Provider.

No work will be undertaken outside of this Services Agreement without the prior approval of the Service Recipient.

4.0 PERFORMANCE MEASURES

The Services Provider will meet semi-annually, or as requested by the Services Recipient, with either the President, or their designate, of the Services Recipient to review the performance of the Services Provider from the last such meeting including an assessment of the value added of governance review and audit findings, adequacy of addressing significant risk areas, responsiveness to Services Recipient concerns, and level of disruption to operations caused by audits.

Based on this assessment, the Services Provider will determine the necessary action steps, implement and follow-up to ensure problems are resolved where possible.

5.0 PROBLEM RESOLUTION PROCEDURES

The Manager, Audit Services of the Services Provider will have a direct reporting mechanism to the President of the Services Recipient and the responsible Audit, Finance & Risk Committee for audit related concerns of the Services Recipient. For the administration of audits and reviews, the Manager, Audit Services will report to the Vice President, Finance and IT or their designate.

Any concerns with respect to the performance of Audit Services should be brought to the attention of the Manager, Audit Services if they cannot be resolved with the Audit Services staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The services described in this Schedule shall be charged at hourly rates, based on the experience of the staff utilized, as detailed in the table below. This amount excludes any reasonable out of pocket expenses, which will be charged at cost. The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately by and agreed upon in advance with the Services Recipient. The budgeted amount for 2011 is $15,000, and this will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.

	Charge-out rate per hour		
Staff Level	**2011**	**2012**	**2013**
Audit Analyst / Sr. Audit Analyst	**$ 68**	**$ 70**	**$ 72**
Advisor / Senior Advisor	**$ 83**	**$ 85**	**$ 87**
Supervisor	**$ 110**	**$ 113**	**$ 115**
Manager / IT Audit Manager	**$ 160**	**$ 163**	**$ 168**
Director/Senior Manager (Chief Auditor)	**$ 210**	**$ 215**	**$ 220**

Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payments for services rendered are due in accordance with the schedule set out in the Agreement.

Dated this 24th **day of** March, 2011

APPROVED AS TO FORM ENBRIDGE LAW TP

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFÈRE INC.

Per: _____

Jamie LeBlanc – General Manager

Per: _____

Lise Manuel – Manager Regulatory Affairs & Budgets

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. (the "Agreement").

1.0 PREFACE

This Schedule is intended to identify ***Corporate Security Services*** to be provided to Gazifere Inc. (the "Services Recipient"), by Enbridge Gas Distribution Inc. (the "Services Provider").

The services defined in this Schedule are to be provided to the Services Recipient for a period of three years (03), commencing January 1, 2011 and ending December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

Upon request of the Services Recipient, the Services Provider will:

- Conduct physical security reviews of the Service Recipient facilities and make recommendations as required;
- Conduct investigations into matters of impropriety or illegality and provide written reports detailing results of the investigation and recommendations of action to be taken; and
- Assist the Services Recipient human resources personnel in complaints of harassment, compensation claims and other sensitive issues.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider will:

- Provide written reports detailing the results of the work requested and any related recommendations within a reasonable timeframe, agreed to by both parties when work on the Services Recipient request commences;
- Respond to standard requests within 24 hours and provide an estimate of the time to complete the request to the Services Recipient within 7 days; and
- Respond to urgent requests within 2 hours.

The Services Recipient will:

- Submit all requests to the Services Provider in writing, indicating the nature of the request and the requested timeframe for completion; and
- Provide access to all facilities and information deemed necessary by the Services Provider to complete a request.

4.0 PERFORMANCE MEASURES

The Service Levels related to request will be met 90% of the time. Once a request is initiated, the delivery of services and performance thresholds will be agreed to by both and will be based on the projected complexity of the request. These thresholds will be exceeded or met 90% of the time.

5.0 PROBLEM RESOLUTION PROCEDURES

Any shortfall in the performance measures identified by the Services Recipient will be communicated in writing to the Services Provider. The Services Provider will provide a written response within 30 days, based on the discussions with the Services Recipient, identifying the sources of the performance shortfall and remedial action to be taken.

Failing resolution on the remedial action within 60 days of the original communication from the Services Recipient, the Problem/Conflict Resolution procedure set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

During the Term of this Schedule, the services described above and any additional regulatory service will be charged at the following hourly rates:

	Effective Jan 1/2011	**Effective Jan 1/2012**	**Effective Jan 1/2013**
Manager	**$180.00**	$183.78	$188.19
Supervisor	**$135.00**	$137.84	$141.15

The estimated dollar amount budgeted for this service in 2011 is $1,000. **This rate will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.**

Service rates may be changed in subsequent years upon at least 30 days notice from the Services Provider to initiate discussions in good faith with the Services Recipient. Payment notices for services provided under this Schedule shall be submitted to the Services Recipient once each calendar month and are payable in accordance with the schedule set out in the Agreement. The Services Provider shall ensure that all services delivered hereunder (either through the Services Provider's own resources or by external counsel) are provided in accordance with the terms of this Schedule.

The Services Recipient will be required to reimburse the Services Provider for reasonable out of pocket expenses incurred by the Services Provider in accordance with the Agreement.

All amounts charged to the Services Recipient by external legal counsel and external consultants (including both fees and disbursements) shall be paid in full by the Services Recipient on a timely basis.

Dated this 24th **day of** March, 2011

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFERE INC.

Per: _____
JAMIE LEBLANC – GENERAL MANAGER

Per: _____
Vice President, Manager Regulatory Affairs & Budget

SERVICE SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. (THE "AGREEMENT")

1.0 PREFACE

This Schedule identifies ***Dispatch & Call Answering Services*** (the "Services") to be provided to Gazifere Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc. (the "Services Provider").

Subject to earlier termination by the Services Recipient, as provided for herein, the Services will commence January 1, 2011 and end December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. The Services Recipient may terminate the Services upon thirty (30) days written notice to the Services Provider, and the Services Provider may terminate the Services upon ninety (90) days written notice to the Services Recipient, for any reason.

2.0 DEFINITION OF SERVICES

The Services Recipient requires a 24 hour dispatch and call answering service for back-up, business resumption purposes. The Services recipient has its own 24 hour dispatch and call answering service in-house, however requires the Services Provider to perform dispatch and call answering functions during situations when it is unable to perform these functions, for example during phone system disruptions or building evacuations, and also during other infrequent times that the Services Recipient call centre personnel and/or dispatch personnel are not available.

In each instance that the Services are required, the Services Recipient dispatch personnel will contact the Services Provider dispatch personnel by telephone and confirm the need for Services, which if confirmed by the Services Provider, will commence by the Services Recipient initiating an automatic transfer of inbound calls to the Services Provider.

The Services Provider acknowledges that the Services Recipient provides 24 hour call answering services to another affiliate, Enbridge Gas New Brunswick LP ("EGNB"). In the course of providing the Services to the Services Recipient, the Services Provider will also provide the Services, as required, to EGNB in accordance with the Intercorporate Services Agreement between EGNB and the Services Recipient.

Subject to the foregoing, the services provider agrees to provide the following Services:

1. Dispatching and coding back completion of service, locate and emergency calls;
2. Preparation of weekly and monthly statistical reports upon request; and
3. Call answering services in both French and English, as required.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider will:

1. Ensure that all calls are dispatched and completion coded back as per the Services Recipient's policies and procedures.
2. Ensure that the necessary service levels are maintained to meet the Service Recipient's commitments to customers and outside agencies.
3. Ensure appropriate staffing and resources are available to respond in a timely manner to requests for service.

4. Maintain a "Fire Phone" service accessible to local emergency services organizations in New Brunswick.

The Services Recipient will:

1. Provide up-to-date information as noted below:
   - Weekly schedule of on-call personnel
   - List of personnel including office, home, pager and cellular telephone numbers
   - List of telephone numbers for utilities, municipalities, emergency services (fire, police), and regulatory authorities.
   - Regional maps; and
   - Training scripts and training manuals, as required.
2. Notify the service provider of any extraordinary commitments to customers and agencies in advance.

4.0 PERFORMANCE MEASURES

1. Performance measures developed for Service Provider's own operations will apply, with modifications as mutually agreed to in writing by the parties from time to time.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of all Services should be brought to the attention of the General Manager, Eastern Region, if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures identified in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The Services will be charged in accordance with the attached price schedule.

The costs of goods or services from third parties will be charged separately to the Services Recipient. Payment for Services is to be made in accordance with the Agreement.

Dated this 7th **day of** June, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law & Information Technology

GAZIFÈRE INC.

Per: _____
General Manager
Jacinthe Leblanc

Per: _____
Manager Regulatory Affairs & Budgets
LISE MAUVEL

Schedule of Prices

Call Type	Cost/Call 2011	2012	2013
Service Call i.e escape, unlock, meter work ect (5min/call)	$ 5.52	$ 5.64	$ 5.78
Follow-up on calls - Past Priority, CR12's (5 min/call)	$ 5.52	$ 5.64	$ 5.78
Locate - Schedule locate appt for other Utilities, Municipalites, etc (3 min/call)	$ 3.31	$ 3.38	$ 3.46
Locate - Schedule appt for NB to complete work (per utility) (5 min/call)	$ 5.52	$ 5.64	$ 5.78
Service Check - provide bldg entry point, Tie-in location at the main (per service) (2 min/call)	$ 2.21	$ 2.26	$ 2.31
Service Damage includes maintaining log (5 min/call)	$ 5.52	$ 5.64	$ 5.78
Main Damage - includes maintaining log and ensuring all necessary CR12's are complete (per minute call rate)	$ 1.10	$ 1.12	$ 1.13
Report Preparation (per hour rate)	$ 66.24	$ 67.63	$ 69.25

The above rates are adjusted by an inflation factor of 2.1% for 2012 and an additional 2.4% for 2013.

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. DATED JANUARY 1, 2011, (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Environmental, Health & Safety Services*** ("Services") to be provided to Gazifere Inc. (hereinafter referred to as the "Services Recipient") by Enbridge Gas Distribution Inc. (hereinafter referred to as the "Services Provider").

The Services defined in this Schedule are to be provided to the Services Recipient for a period of three years (03), commencing January 1, 2011 and terminating December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with the following services on an as requested basis:

1. Environment Health and Safety Management System Support; and
2. Worker's Compensation Support Services, Vehicle Collision Support, and Health Support Services including health management of ill or injured employees, facilitation of fitness-for-work evaluations, and consultation with managers and employees as a resource.
3. Notification of pending or actual changes to federal or provincial EHS-related regulations which may impact the operations of the Services Recipient.
4. On-Road Evaluation and Safety Instruction for vehicle drivers.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider will:

- Deliver all services within agreed timeframes and provide the quality and completeness specified by the Services Recipient.

The Services Recipient will:

- Be responsible for designating the nature of the services to be performed by the Service Provider and verifying that the results achieved by the Service Provider are satisfactory.
- Provide direction and communicate desired timeframes and budgets to the Services Provider.
- Communicate, in a timely manner, changes to scope and timing.
- Submit to the Services Provider, within 48 hours of the occurrence of a work-related injury to an employee of the Services Recipient, a completed Employers' Workers Compensation Injury Report and a completed Supervisors' Accident Investigation Report.

4.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of all services, including failure to meet performance measures, should be brought to the attention of the Service Provider's Vice President Engineering if they cannot be resolved with the staff directly. Failing resolution, the Problem / Conflict Resolution procedures identified in the Agreement will be followed.

5.0 PRICING AND CONDITIONS

The services described in this Schedule shall be charged, and payment notices sent, as services are rendered at the rates identified in the attached Schedule of Prices for 2011. There will be an inflation rate of 2.1% for 2012, and 2.4% for 2013 applied to the 2011 rates. Payments for services rendered are due in accordance with the schedules set out in the Agreement.

Dated this 24th **day of** March, 2011

APPROVED AS TO FORM ENBRIDGE LAW TP

Enbridge Gas Distribution Inc.

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law &
Information Technology

Gazifere Inc,

Per: _____

Jamie LeBlanc - General Manager

Per: _____

Asset Planning / Regulatory Affairs & Budgets

Affiliate: Gazifere Inc.

	ITEM	MECHANISM	RATE
1.	EHS-MS Support Program	Direct Billing from Timesheets	See Below
2.	Workers' Compensation, Vehicle Collision, Health and EVAP Support	Payroll to verify Gazifere headcount monthly	$6.73 / EE / month
3.	Notification of EHS-related Regulatory Changes	Monthly Fixed Fee	$40.84 / month
4.	On-Road Evaluation and Safety Instruction for vehicle drivers	Direct Billing from Timesheets	See Below

RATES

A – EHS Manager	$125/hr + Expenses
B – EHS Specialist/ Occupational Health Manager	$85/hr+ Expenses
C – Occupational Health Nurse	$ 64/hr + Expenses

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011, BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify **Engineering and Operations Services** to be provided to Gazifere Inc (the "Services Recipient"), by Enbridge Gas Distribution Inc. (the "Services Provider"). This Schedule terminates and replaces any prior schedule for Engineering and Operations Services entered into by the parties.

The services defined in this Schedule are to be provided to the Services Recipient for a period of three (3) years, commencing January 1, 2011. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with the following Engineering and Operations services on an as requested basis:

1. Policy and Procedure development pertaining to Engineering Design, Planning, Construction, Pressure Regulation, Operations and Maintenance, Service, Quality Acceptance and Safety; Technical Training Management and Module Development; OQ/CAP Program Management;
2. Provision of specialized Engineering Services including Incident Investigation and follow up;
3. Laboratory Services;
4. Project Management, System and Facility Design, Drafting and Records Services;
5. Training module development pertaining to Engineering Design, Planning, Construction, Pressure Regulation, Operations and Maintenance, Service, Quality Acceptance and Safety;
6. Service, Construction, Operations and Maintenance Training;
7. General Engineering, Design, Cost Estimating and Operations consulting;
8. New Product Approvals;
9. Inspection Services;
10. Operations Services, including training, leak survey, corrosion survey, welding, measurement and regulation, tapping, stopping and construction and maintenance support.
11. Chart Processing - The processing of charts removed from volume pressure temperature chart recorders and PFM card processing for all Gazifere high pressure accounts the corrected calculated volumes will be forwarded to ABSU for the purpose of producing the customer bill.
12. AMR Processing - The processing of all electronic volume data transferred a minimum of once per day for each customer connected to the Services Provider electronic data gathering system (Metretek). The volume data will be reviewed for reasonability and then passed on to ABSU for the purpose of producing the customer bill.
13. Meter History - The management of all active meter records as required by federal legislation contained in "The Electricity and Gas Inspection Act". This would include the management of functions such as the sample and government inspection (GI) programs.

14. Meter Repair/Accreditation/Purchasing - Meter supply services, which would include the purchasing and sealing of all meters required by the Service recipient.
15. Right-of-Way services for land acquisition and disposal.
16. Monthly and Ad-hoc data extracts and reports.

In addition to the above, Gazifere and EGD will provide to each other emergency on-call services through an equal sharing of qualified Operations personnel for supervisor and performance standards inspections rotations. Neither party shall charge the other party for these services, provided that the shared personnel from each of the parties are providing the services for a substantially equivalent amount of time, as reasonably determined by the parties. If either party determines that its personnel are performing a larger proportion of the services than the other party, they may issue a charge to the other party for that additional proportion of work being performed. Such charge shall be consistent with the rates set out in the attached Schedule of Prices.

3.0 SERVICE LEVELS

The Services Provider will:

- Deliver all services within agreed timeframes and provide the quality and completeness specified by the Service Recipient

The Services Recipient will:

- Be responsible for designating the nature of the services to be performed by the Services Provider and verifying that the results achieved by the Services Provider are satisfactory.
- Provide direction and communicate desired timeframes and budgets.
- Communicate, in a timely manner, changes to scope and timing.

4.0 PERFORMANCE MEASURES

The Service Provider will meet all agreed timeframes and meet deliverable quality set forth by the Services Recipient.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of all services should be brought to the attention of the Services Provider's Vice President Engineering if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures identified in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

Except for emergency on-call services, the services described in this schedule shall be charged as services are rendered at the rates identified in the attached Schedule of Prices. This rate shall be increased by two point one percent (2.1%) in CY 2012 and two point four percent (2.4%) in CY 2013 annually on the anniversary date of this Schedule. The Services Provider reserves the right to revise the 2011 estimate set out in the Schedule of Prices in the event that the services rendered are significantly more or less than the estimated amount. Payments for services rendered are due in accordance with the schedule set out in the Agreement.

Dated this 15th **day of** July, 2011.

Enbridge Gas Distribution Inc.

APPROVED AS TO FORM
ENBRIDGE LAW

Per: _____
Jamie Milner
Vice President, Pipeline Integrity & Safety

Per: _____
Narin Kishinchandani
Vice President, Finance

Gazifère Inc.

Per: _____ - Jamie LeBlanc
General Manager

Per: _____ - Lise Mauvec
Manager, Regulatory Affairs & Budgets

Engineering Department
Proposed Affiliate Transactions
Calendar Year 2011

Affiliate: Gazifere Inc.

2011 Engineering estimate: $150,017
2011 Operations estimate: $ 23,763

	ITEM	MECHANISM	RATE
1.	Technical Engineering Policies and Procedures	Customer Ratio System	$45,631 Annually
	Technical Training Services	Customer Ratio System	$40,561 Annually
2.	Environmental Assessment Program	Direct Billing from Timesheets	See Below
3.	EMS Support Program	Direct Billing from Timesheets	See Below
4.	Other Engineering Services	Direct Billing from Timesheets	See Below
5.	Laboratory Services	Direct Billing from Timesheets	See Below
6.	Engineering, Technical Training Services	Direct Billing from Timesheets	Rate B (see below)
7.	Drafting and Records Services	Direct Billing from Timesheets	Rate E (see below)
8.	System & Facility Design, Technical Training Services	Direct Billing from Timesheets	Rate C (see below)
9.	Regional Measurement and Regulation, Corrosion	Direct Billing from Timesheets	Rate D (see below)
10.	Leak Survey, Wielding, Tapping and Stopping	Direct Billing from Timesheets	Rate F / G (see below)
11.	Regional Performance Measures and Training	Direct Billing from Timesheets	Rate D (see below)
12.	Chart Processing	Customer Ratio System	$4.81 Lines/MTH
13.	AMR processing	Customer Ratio System	$18.74 Accts/MTH
14.	Meter History	Customer Ratio System	$0.01 Records/MTH
15.	Meter Repair/Accreditation/Purchase	Customer Ratio System	$9.45 Meters/ Yr
16	Reporting and Data Extract Services	Direct Billing from Timesheets	Rate H (see below)

RATES

A – Senior Manager/Director (Grade 010+)	$179/hr + Expenses
B – Project/Program Manager (Grade 007-009)	$153/hr + Expenses
C – Project Leader/Network Analysis (Grade 006)	$128/hr + Expenses
D – Inspectors (Grade 005)	$118/hr + Materials & Expenses
E – Lab Technologist/Field Technician/Drafting/Records (Grade 004)	$92/hr + Expenses
F – Operations Field Time - Straight Time	$75/hr + Materials & Equipment
G – Operations Field Time – Overtime	$112.50/hr + Materials & Equipment
H- Senior Analyst	$102/hr + Expenses

2010 Equipment Costs

Description	Unit	Rate	10% Increase
Stopple Equipment 1" - 2" Double	Hour	$ 606.37	$ 667.01
Stopple Equipment 1" - 2" Single	Hour	$ 365.15	$ 401.67
Stopple Equipment 12" Double	Hour	$ 1,016.00	$ 1,117.60
Stopple Equipment 12" Single	Hour	$ 785.00	$ 863.50
Stopple Equipment 3" Double	Hour	$ 755.00	$ 830.50
Stopple Equipment 3" Single	Hour	$ 503.25	$ 553.58
Stopple Equipment 4" Double	Hour	$ 668.85	$ 735.74
Stopple Equipment 4" Single	Hour	$ 525.50	$ 578.05
Stopple Equipment 6" Double	Hour	$ 868.00	$ 954.80
Stopple Equipment 6" Single	Hour	$ 562.38	$ 618.62
Stopple Equipment 8" Double	Hour	$ 920.75	$ 1,012.83
Stopple Equipment 8" Single	Hour	$ 698.37	$ 768.21
Tapping Equipment 1"-2" Double	Hour	$ 77.97	$ 85.77
Tapping Equipment 1"-2" Single	Hour	$ 62.37	$ 68.61
Tapping Equipment 12" Double	Hour	$ 432.12	$ 475.33
Tapping Equipment 12" Single	Hour	$ 348.12	$ 382.93
Tapping Equipment 3" Double	Hour	$ 246.50	$ 271.15
Tapping Equipment 3" Single	Hour	$ 198.50	$ 218.35
Tapping Equipment 4" Double	Hour	$ 249.72	$ 274.69
Tapping Equipment 4" Single	Hour	$ 201.12	$ 221.23
Tapping Equipment 6" Double	Hour	$ 265.87	$ 292.46
Tapping Equipment 6" Single	Hour	$ 214.37	$ 235.81
Tapping Equipment 8" Double	Hour	$ 285.85	$ 314.44
Tapping Equipment 8" Single	Hour	$ 230.25	$ 253.28
Truck - Utility Fitter	Hour	$ 24.46	$ 26.91
Truck - Tapping	Hour	$ 44.55	$ 49.01
Truck - Highway Tractor c/w 18 Ton Crain	Hour	$ 64.62	$ 71.08
Truck - Hydro Vac	Hour	$ 200.40	$ 220.44
Truck - Pickup/Misc Vehicle	Hour	$ 18.89	$ 20.78
Truck - Single Axle Dump	Hour	$ 30.55	$ 33.61
Truck - Stake 1 Ton c/w Tools	Hour	$ 23.65	$ 26.02
Truck - Tandem Axle Dump	Hour	$ 39.51	$ 43.46
Truck - Tri-Axle Dump	Hour	$ 44.93	$ 49.42
Truck - Utility c/w Compressor	Hour	$ 39.32	$ 43.25
Truck - Vacuum Sucker	Hour	$ 64.29	$ 70.72
Truck - Welding Rig	Hour	$ 33.87	$ 37.26

Stopple Materials

Type	Description - with TDW Part Numbers	Price
NON STOCK	CUP 1" SHORTSTOPP SEALING - 080114-0001-00	$ 82.86
NON STOCK	CUP 1.25" SHORTSTOPP SEALING - 08-0114-0125-00	$ 25.58
NON STOCK	CUP 1.5" SHORTSTOPP SEALING - 080114-0015-00	$ 30.69
NON STOCK	CUP 2" SHORTSTOPP SEALING - 08-0114.0002-00	$ 25.58
NON STOCK	CUP 4" SHORTSTOPP SEALING - 08-0114-0004-00	$ 63.43
NON STOCK	CUP 6" SHORTSTOPP SEALING - 08-0114-0006-00	$ 114.58
NON STOCK	CUP 8" SHORTSTOPP SEALING - 08-0114-0008-00	$ 159.59
NON STOCK	CUP 2" SHORTSTOPP SEALING SCHED 10 TO 40 - 08-0501-0200-00	$ 33.76
NON STOCK	ELEMENT 2" SEALING SHORTSTOPP 275 -08-0947-0002-00	$ 144.24
NON STOCK	ELEMENT 4" SEALING SHORTSTOPP 275 - 08-0947-0004-00	$ 202.55
NON STOCK	ELEMENT 6" SEALING SHORTSTOPP 275 - 08-0947-0006-00	$ 234.27
NON STOCK	ELEMENT 8" SEALING SHORTSTOPP 275 - 08-0947-0008-00	$ 303.83
NON STOCK	ELEMENT 12" SEALING SHORTSTOPP 275 - 08-0947-0012-00	$ 491.04
NON STOCK	ELEMENT 6" SEALING S/S 275 THINWALL - 08-0948-0006-00	$ 234.27
NON STOCK	ELEMENT 8" SEALING S/S 275 THINWALL - 08-0948-00008-00	$ 303.83
NON STOCK	SEALING ELEMENT 2" (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0385-0005-XX	$ 147.31
NON STOCK	ELEMENT 3" SEALING STOPPLE (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0385-0005-XX	$ 270.07
NON STOCK	ELEMENT 4" SEALING STOPPLE (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0036-0005-XX	$ 336.57
NON STOCK	ELEMENT 6" SEALING STOPPLE (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0040-0005-XX	$ 343.73
NON STOCK	ELEMENT 8" SEALING STOPPLE (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0246-0005-XX	$ 391.81
NON STOCK	ELEMENT 10" SEALING STOPPLE (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0247-0005-XX	$ 433.75
NON STOCK	ELEMENT 12" SEALING STOPPLE (SPECIFY PIPE I.D. WHEN ORDERING) - 08-0248-0005-XX	$ 616.87
NON STOCK	2" SEALING ELEMENTS S/SII F/200 psi MWP ID 2.062-2.157"	$ 147.31
NON STOCK	3" SEALING ELEMENTS SHORTSTOPP 60 MWP 60 psi. ID 3.068-3.188"	$ 30.69
NON STOCK	4" SEALING ELEMENTS SHORTSTOPP II MWP 200 psi. ID 4.156-4.260"	$ 284.39
NON STOCK	6" SEALING ELEMENTS SHORTSTOPP II MWP 60 psi. ID 6.188-6.249"	$ 165.73
NON STOCK	6" SEALING ELEMENTS SHORTSTOPP II MWP 200 psi. ID 6.187-6.249"	$ 253.70
NON STOCK	10" S/S 275 SEALING CUPS - 08-0947-0010-00	$ 433.75
NON STOCK	KIT,RPR F/2" SHORTCUTT VALVE	$ 10.23

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC AND GAZIFÈRE INC. (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Financial and Business Consulting Services*** to be provided to Gazifère Inc. (the "Services Recipient"), by Enbridge Gas Distribution Inc. (the "Services Provider").

The services defined in this Schedule are to be provided to the Services Recipient for a period of three years (03), commencing January 1, 2011 and terminating on December 31, 2013. Notwithstanding this term, either party has the right to cancel this Schedule on two months written notice. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with Financial and Business Consulting services as required by the Recipient. Work performed can include but shall not be limited to the following:

- Capital budgeting and benefit: cost analysis
- Financial analysis required for regulatory filings
- Budgeting and variance analysis
- Feasibility guidelines and capital requisitions
- Strategic planning (LRP)
- Special Studies

The Service Recipient will provide the required information to the Service Provider in a timely manner to ensure completion of the requested Financial and Business Consulting Services.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider will:

- Ensure completeness and accuracy of the analysis conducted for the Service Recipient.
- Provide the Service Recipient with output (deliverable), which is agreed upon prior to undertaking a special study. The agreement shall define the required output and the timing of the required output.

The Service Recipient will:

- Provide the Service Provider with reasonable notice of the projects expected during the term of the agreement.
- Provide all necessary data required to complete the analysis.

4.0 PERFORMANCE MEASURES

Performance measures will be agreed upon for each individual project prior to the initiation of the project. The measures to be agreed upon can but shall not be limited to the following:

- Timing of completion
- Costs
- Format of output

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of Financial and Business Consulting Services should be brought to the attention of the Analyst performing the agreed upon work. If an agreement cannot be reached with the Analyst then the matter should be brought to the attention of the Analyst's supervisor. The Department Manager should be involved if problem resolution cannot be obtained with the Supervisor. Failing resolution, the Problem / Conflict Resolution procedures identified in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The services described in this Schedule shall be charged in 2011 at an hourly rate of:

Director / Senior Manager	$ 250.00
Manager / Senior Supervisor	$ 175.00
Supervisor	$ 127.00
Senior Clerk	$ 105.00
Junior Clerk	$ 85.00

The 2011 rates will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.

The estimated fees for services described in this Schedule shall be $4,000 in 2011. The foregoing fees are based on an annual calendar year forecast of expected service requirements reasonably determined by the Services Provider. The Services Provider reserves the right to revise this estimate in the event that the services rendered are significantly more or less than the estimated amount. The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately by and agreed upon in advance with the Services Recipient. Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payments for services rendered are due in accordance with the schedule set out in the Agreement.

Non-labour related costs such as materials and supplies, transportation, and travel will be billed (if applicable) to the Services Recipient.

Dated this 24th **day of** March, 2011

Enbridge Gas Distribution Inc.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law & Information Technology

Gazifère Inc.

Per: _____
JAMIE LEBLANC - GENERAL MANAGER

Per: _____
Lisa Lamont / Manager Regulatory Affairs & Budgets

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Fleet and Equipment Services*** (the "Services") to be provided to Gazifère Inc. (hereinafter referred to as the "Services Recipient") by Enbridge Gas Distribution Inc. (hereinafter referred to as the "Services Provider").

The services defined in this schedule are to be provided to the Services Recipient for a period of three years (03), commencing January 1, 2011 and ending December 31, 2013 (the "Term"). The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

In this schedule, the term "fleet" shall mean motor vehicles, including passenger cars and trucks, licensed for use on public roads. The term "equipment" shall mean tools and equipment that are mechanical in nature and used either mounted or in a vehicle or provided for construction and maintenance work.

The Services Provider agrees to provide the Services Recipient with:

(a) Management consulting services, policy recommendations and day-to-day management of fleet vehicles and equipment;
(b) Procurement and replacement of fleet vehicles and equipment to meet job function requirements and agreed standards;
(c) Remarketing and disposal of decommissioned vehicles and equipment;
(d) Fleet and equipment fuel procurement management;
(e) Fleet and equipment maintenance management;
(f) Fleet and equipment supplier management;
(g) Fleet and equipment administration management;
(h) Automobile insurance administration and accident repair management;
(i) Regulatory and corporate safety management as it applies to fleet vehicles and equipment and operators, including delivery of employee training required by the Driver Training Standard;
(j) Vehicle identification and branding management;
(k) Vehicle licence and permit procurement and renewal;
(l) Automobile taxable benefit calculations for proper income tax withholding and reporting;
(m) Coordination of motor vehicle accident claims with the provider of automobile insurance, and
(n) Delivery of vehicles to locations as agreed upon by the Services Provider and Services Recipient at time of order.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider will:

- provide a controlled plan of regular inspection and maintenance to ensure maximum vehicle and equipment availability and compliance with regulatory, environmental and safety standards;
- provide a report that summarizes all vehicle expense information on a monthly basis;
- provide reports as required by risk Management relating to vehicle and automobile claims;
- provide equipment operator training as required;
- provide access to fuel sources on a 24 hours/7 days basis;
- for scheduled inspections and service, return vehicles and equipment to the user within eight hours, or at the start of the next business day if service is scheduled for completion on a night shift, or provide a replacement vehicle at no charge if the work extends beyond eight hours;
- ensure that service can be provided within a reasonable distance from the home location of the vehicle or equipment, Monday to Friday 8:00 a.m. to 4:00 p.m. Local Time; and

- ensure all vehicle operators have access to a vehicle, either rented or from a pool of vehicles 100% of the time.

The Services Recipient will:

- follow the procedures as agreed upon between the Services Provider and the Services Recipient direct its employees to adhere to them;
- provide a point of contact to discuss administration and policy issues;
- provide the Services Provider with the specification and requirements for procurement of all vehicles and equipment covered under this Schedule, including but not limited to Make, Model, Manufacturer as well as quantity;
- agree to use the vendors arranged by the Services Provider and not to use other sources for these services without prior authorization from the Services Provider;
- adhere to the agreed maintenance schedule by making vehicles and equipment available for inspection as arranged;
- provide vehicle odometer readings as requested by the Services Provider for record and maintenance scheduling;
- ensure all Services Recipient employees and agents operating vehicles and equipment subject to this service schedule have the proper training to operate the assigned vehicle ; and
- provide all requests for new vehicles and equipment to the Services Provider in writing.

4.0 PERFORMANCE MEASURES

a) Service level forecasts and performance targets shall be reviewed from time to time and may be revised upon mutual agreement between the Services Recipient and the Services Provider

b) The number of repairs classified as breakdowns will not exceed the number of repairs classified as inspections.

c) With exception of delays due to non receipt of backordered parts, vehicles & equipment brought in for scheduled service & repair will be returned within 8 business hours at a Services Provider facility, otherwise, a replacement vehicle will be provided to the Services Recipient at no charge.

d) With the exception of repair work for accidents and delays due to non receipt of backordered parts, unscheduled service and repairs shall be completed within 2 business days 90% of the time. Replacement vehicles shall be provided at the Services Provider expense whenever the time to complete the unscheduled work exceeds 3 business days.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns on the part of the Services Recipient with respect to the performance of Fleet and Equipment Services should be brought to the attention of the Manager, Fleet and Equipment if they cannot be resolved with the staff directly involved. Failing resolution, the Dispute Resolution procedures in the Agreement will govern.

6.0 PRICING AND CONDITIONS

Fees and costs associated with the services shall be charged to the Services Recipient as follows:

- Fleet, vehicle and equipment management will be billed at a rate of $30.00 per month for each vehicle or equipment unit not mounted on a vehicle including all those active in service, on order or in process of being decommissioned, as shown on the approved fleet list. The Services Recipient is responsible for payment of monthly lease charges with no additional markup;
- Labour for repair and maintenance shall be charged as services are rendered at the rate of $90.00 per hour for fleet vehicles, and $95.00 for equipment units. These rates shall be modified as required based on industry factors, e.g., Chilton Labour Guide and will use the change management process identified in Section 7 of the Agreement to effect a change;
- Parts will be billed at cost plus a markup of 20%;

- Standard pool vehicles will be provided at rates of $25.00 per hour, $48.00 per day, $258 per week or $890 per month, fuel included;
- Licence renewals, replacement of lost plates or validation stickers, driver licence history checks, parking ticket payments and other transactions with the Ministry of Transportation, other provincial or state motor vehicle regulators, municipalities, Highway 407ETR and other toll-charging routes will be handled for the statutory fee
- Vehicle fuel, natural gas, diesel and gasoline, provided from the Services Provider facilities shall be priced at the prevailing market rate;
- Accident claims handling will be performed for a fee of $150 per claim;
- Goods and services provided by third parties that cannot provide a separate invoice will be billed at the rates charged by the third party;
- All work performed at the Services Provider's facility is warranted against defects in materials and workmanship for a period of 90 days or 4,000 kilometers traveled following the service.

The budgeted amount for these services in 2011 is $131,184. The Services Provider reserves the right to revise this estimate in the event that the services rendered are significantly more or less than the estimated amount. The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately by and agreed upon in advance with the Services Recipient. Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payment for services rendered is due in accordance with the schedule set out in the Agreement.

Dated this 24th **day of** March, 2011

Enbridge Gas Distribution Inc.

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law &
Information Technology

Gazifère Inc.

Per: _____

Jamie LeBlanc – General Manager

Per: _____

Last Name / Manager Regulatory Affairs & Budgets

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. (the "Agreement")

1.0 PREFACE

This Schedule identifies ***Governance and Internal Controls Services*** to be provided to Gazifere Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc. (hereinafter referred to as the "Services Provider"), to deliver the Services.

The services defined in this Schedule are to be provided to the Services Recipient for a period of three years, commencing September 1, 2010 and ending December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider will develop an overall Governance plan in consultation with Senior Management and based upon an assessment of corporate risks. The Services Provider agrees to use a systematic and disciplined approach to evaluate and recommend improvements to the effectiveness of the Services Recipient's risk management, control and governance processes.

The Service Provider will provide guidance and assistance to allow the Service Recipient to be compliant with the current Sarbanes-Oxley legislation, if required, and/or include an assessment of internal controls over Financial Reporting, as well as, testing the design and operating effectiveness of those same internal controls.

The detailed planning for individual governance reviews will be performed prior to commencement of fieldwork and will include a review of the planned scope, objectives and timeframe with Services Recipient management.

3.0 SERVICE LEVELS

The Services Provider is responsible for the following:

- Consult with management of the Services Recipient prior to finalization of the overall governance and internal control review to ensure that the significant risk areas of the Services Recipient will be adequately addressed. Subsequently, if modifications to the plans are required, have on-going discussions with management to ensure all significant risk areas continue to be adequately addressed;

- Work with the Service Recipient to complete documentation required to become compliant with Sarbanes-Oxley legislation. This will include defining process flow, key

controls and testing of these key controls.

- Review the requests for additional Governance and Internal Control requirements and advise as to whether or not it is able to or should take action to address within one week of receiving sufficient information to assess the related scope, objectives, timing, and resources required;

- Work with the Services Recipient in finalizing the detailed scope, objectives and timing for individual governance and internal control review to ensure management's concerns are appropriately addressed and least possible disruption to operations will result;

- Ensure all governance and internal control reviews are performed and the related reports prepared by a person or persons having adequate technical training and proficiency in governance;

- Issue a report to management that summarizes the significant governance and internal control review within a reasonable period after the completion of field work; and

The Services Recipient is responsible for the following:

- Make available the necessary and appropriate level of resources on a timely basis and fully disclose and accurately represent the required information to allow the detailed planning and execution of governance reviews to occur;

- Have senior management, including the President and other staff members as appropriate, meet with the Services Provider to ensure that the governance and internal control plans continue to adequately address significant risk areas;

- Where required, provide responses to governance and internal control review within agreed timing of receiving the draft governance and internal control review from the Services Provider.

No work will be undertaken outside of this Services Agreement without the prior approval of the Services Recipient.

4.0 PERFORMANCE MEASURES

The Services Provider will meet semi-annually, or as requested by the Services Recipient, with either the President, or their designate, of the Services Recipient to review the performance of the Services Provider from the last such meeting including an assessment of the value added of
governance review, adequacy of addressing significant risk areas, responsiveness to Services Recipient concerns, and level of disruption to operations caused by governance reviews and audits.

Based on this assessment, the Services Provider will determine the necessary action steps, implement and follow-up to ensure problems are resolved where possible.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of Governance and Internal Controls Department should be brought to the attention of the Governance and Internal Control staff performing the agreed upon work. If agreement cannot be reached, with the Governance and Internal Control staff involved, then the matter should be brought to the attention of the supervisor. The Department Manager should be involved if problem resolution cannot be obtained with the Supervisor. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

During the Term of this Schedule, the services described above and any additional **Governance and Internal Controls Services** will be charged at the following hourly rates:

	Effective Jan 1/2011	**Effective Jan 1/2012**	**Effective Jan 1/2013**
Manager Governance and Internal Controls	**$172.00**	**$175.61**	**$179.82**
Manager Internal Controls	**$142.00**	**$144.98**	**$148.46**
Leader Governance and Internal Controls	**$96.00**	**$98.02**	**$100.37**
Business Process Analyst	**$96.00**	**$98.02**	**$100.37**

The 2012 and 2013 rates have been derived by applying an inflation factor of 2.1% in 2012 and 2.4% in 2013 on the 2010 market rate. The estimated amount of services to be provided for 2011 is CAD $20,000 per annum.

The foregoing fees are based on an annual calendar year forecast of expected service requirements reasonably determined by the Services Provider. The Services Provider reserves the right to revise this estimate in the event that the services rendered are significantly more or less than the estimated amount.

Non-labour related costs such as materials and supplies, transportation and travel will be billed to the Service Recipient.

Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payments for services rendered are due in accordance with the schedule set out in the EI-EGD Agreement. Enbridge hereby guarantees all such payments.

Enbridge hereby directs the Services Recipient to pay the Services Provider for all Services provided hereunder. Enbridge reserves the right to amend the foregoing payment direction upon written notice to the Services Recipient.

Dated this 24th **day of** March, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFERE INC.

Per: _____

JAMIE LEBLANC – GENERAL MANAGER

Per: _____

Lise Mauviel / Manager Regulatory Affairs & Projects

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Benefits, Pension, Employee Record Admin. Payroll, Human Resources Information Services (HRIS) and HR Consulting Services*** to be provided to GAZIFÈRE INC. (hereinafter referred to as the "Services Recipient"), by ENBRIDGE GAS DISTRIBUTION INC. (hereinafter referred to as the "Services Provider").

The Services defined in this schedule are to be provided to the Services Recipient for a period of **36 months**, commencing January 1, 2011. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with administrative services in six distinct areas: Payroll, Employee Benefits, Pension, Employee Record Administration, HRIS and HR Consulting. Additional services may be supplied on a fee for service basis in the Services. Provider's discretion upon request of the Services Recipient.

Services to be provided by the Services Provider shall include acting as a liaison with insurance carriers, consultants, actuaries, the Services Recipient's Human Resources staff and the Services Recipient's employees; as well supplying employee relations services. Special requests for services not expressly described herein, or customizations must be agreed upon by both parties prior to implementation of the service. The fees for these special requests will be based on the hourly rates provided herein, or agreed to on a fee for service basis.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider is responsible for the following:

Payroll Services

- Generate pay deposits dictated by the employee's pay frequency in accordance with established the payroll schedule available on elink. Provide on-line pay advice confirmation statements to the Services Recipient. Paper statements may be available for employees who do not have access to a computer.
- Maintain and change compensation tables as requested by the Services Recipient within seven (7) business days of the request received by the Services Provider; changes resulting from large re-organizations will be made within ten (10) business days.
- Update payroll system with Quebec tax amendments.
- Process adhoc payments requested in the next scheduled payroll run providing they are received at least 48 hours prior to the cutoff.
- Deliver all T4s, T4As and Releve 1 to the Services Recipient three working days prior to the end of the February.

Pension & Benefit Administrative Services

- Maintain accurate records for the administration of the pension plan and employee benefit programs of the Services Recipient includes enrolling new hires, status changes and termination / retirements.
- Pay benefit vendors promptly and charge Recipient with the actual usage in addition to administration fees. (Exception: Sun Life will be billed directly to the Services Recipient.) All vendors are to be paid within seven (7) business days of receipt of invoice.
- Prepare all monthly, quarterly and yearly reports required by the Services Recipient for the

administration of the pension plan and employee benefit programs including regulatory reporting, actuarial valuation, reports for the Pension Administration Committee and on-going information for the Actuarial firm.
- Remit contributions for the Employee Savings Plan, Tax Free Savings Account and Defined Contribution pension plan on behalf of the Services Recipient twice a month (mid month and two working days prior to end of month. Value of contributions charged back to Services Recipient by end of following month.
- Provide all year end employee health taxable benefit data by the second week in February of the following year.
- Discuss proposed changes to programs of the Services Provider to determine the impacts or changes required by the Services Recipient.
- Discuss issues related to plan administration, benefit coverage, or premium levels.

General Administration
- Prepare invoices for monthly HR Administrative Services on a monthly basis for third party remittances within seven *(7)* business days of month end to be forwarded to the Services Recipient for payment.
- Implement new business requirements requested by the Services Recipient within a reasonable timeframe committed to by the Services Provider prior to work commencing.

- Provide access to the file room where employee records are maintained.

HRIS / HR Systems
- Provide security administration, system support and table changes for current benefit plans on an on-going basis within ten (10) business days of the received request by the Services Provider from the Services Recipient.
- Provide regularly scheduled reports to the Services Recipient with the guidelines established.
- Respond to inquiries from the Services Recipient or Services Recipient's staff within one (I) business day of the initial request.

Projects
- Provide a detailed project plan utilizing the Human Resources Project Management template for each major Compensation or Benefits initiative requested by the Services Recipient to be conducted by the Services Provider.
- Provide an estimate of the time required to implement any program changes within one (1) week of receiving a documented change request from the Services Recipient.

The Services Recipient will:

- Maintain timely and up-to-date employee records and profiles for program administration e.g. vacation, disability programs etc...
- Initiate employee transactions in writing for new hires and terminations as well as intra and interdepartmental moves (i.e. promotions) intercompany transitions and employee leaves (e.g. maternity leave) in accordance with Identity and Access Management guidelines.
- Remit payments for benefit invoices received from the Services Provider within five (5) business days of receipt.
- Notify the Services Provider of changes required to programs at least thirty (30) days in advance to allow for system and administrative review prior to implementation.
- Provide all requests for system changes to HR EBS mailbox.
- Ensure that all requests for major initiatives are delivered to the Services Provider in writing.
- Complete all new employee sign-up's, this includes collecting all required information
- Maintain accurate employee data.
- Remit deductions and premiums, along with the appropriate employer's contribution, where applicable, to the appropriate entity (i.e. Revenue Canada and Quebec, United Way, CSST, etc.) by the prescribed dates.
- Provide all year end employee taxable benefit data to the Services Provider by January 15th

of the following year in the format specified by the Services Provider.
- Ensure all time reported for weekly paid employees is approved in the time reporting system by 10:00 a.m. on the following Monday, except where Monday is a Statutory Holiday, when time reporting records must be approved by 10:00 a.m. on Tuesday. Please note this means eField entries need to be approved by 9:00 a.m. each Monday.

4.0 PERFORMANCE MEASURES

The delivery of these services will be measured by:
1. The service levels identified per activity above related to responding to requests being met 100% of the time.
2. All activities for which a project plan is developed will be delivered with 100% of the estimated time and cost.
3. Any non-compliance identified as a result of work done by the Services Provider.
4. Payroll deposits will be made to employee's bank accounts according to the payroll schedule 98% of the time each year.
5. Time & Labour information processed accurately, based on information entered by the Services Recipient, in the Human Resources Information System 100% of the time, as measured by resolution of employee issues.
6. Delivery of reports to Services Recipient and external agencies as identified in the payroll schedule 95% of the time.
7. The Service Provider will deliver legislated remittance requirements to the Services Recipient within two (2) days of each confirmed payroll run, 100% of the time.
8. Payroll related input data and adjustments to employee records, managed by the Services Provider, will be completed accurately 98% of the time.

The Services Provider will establish meetings as required to discuss Compensation and Benefits issues related to the Service Recipient as well as review the metrics identified at the request of the Services Recipient.

5.0 PROBLEM RESOLUTION PROCEDURES

If an issue is identified by either the Services Provider, or the Services Recipient as requiring resolution, the other party will be advised to resolve the issue as quickly as possible. Changes will be implemented and documented. Any issues which cannot be resolved quickly will be escalated to progressively higher levels of management within the Human Resources departments of the Services Provider and Services Recipient to effect a resolution.

If the Services Recipient and Services Provider cannot reach agreement on the remedial action within sixty (60) days of the original communication from either the Services Recipient or Services Provider, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The services described in this Schedule shall be charged to the Services Recipient in accordance with the type of service delivered:

	2011	2012	2013
Pension Administration per employee per month	$5.42	$5.53	$5.67
Benefit Administration per employee per month	$7.30	$7.45	$7.63
Employee Data Maintenance (records storage & handling) per employee per month	$1.15	$1.17	$1.20
Payroll Services per statement per month	$4.60	$4.70	$4.81
PeopleSoft maintenance will be billed based on number of queries / system changes requested. These rates are hourly rates.	$105.00	$107.00	$109.00

- A hourly rate will be charged for any ad hoc services delivered in accordance with the following schedule:

	2011	2012	2013
Director	$177.00	$181.00	$185.00
Business Partner / Mgr	$115.00	$117.00	$120.00
HR Consultant / Assoc Bus. Partner	$81.00	$83.00	$85.00
HR Coordinator	$66.00	$67.00	$69.00

- Any remaining services shall be billed as services are rendered based on the market value of the service provided e.g. Higher Education Award Program.

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The Services Recipient will:

- Be charged directly for all fees related to a system change that is not related to the Services Provider but is required by the Services Recipient.
- Ensure monthly invoices will be processed accurately within thirty (30) days of date of invoice.

Dated this 24th **day of** March, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM ENBRIDGE LAW TP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFERE INC.

Per: _____
JAMIE LE BLANC - GENERAL MANAGER

Per: _____
Senior Manager Regulatory Affairs & Projects

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***IT Consulting and Professional Services*** to be provided to Gazifere Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc. (the "Services Provider").

2.0 TERM

The Services defined in this Schedule are to be provided to the Services Recipient for a period of thirty six (36) months commencing January 1, 2011 and terminating December 31, 2013. The term of this Schedule may be renewed in accordance with Section 10 of the Agreement. Notwithstanding the provisions of Section 24 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

3.0 IT CONSULTING AND PROFESSIONAL SERVICES

Professional Services encompass a variety of activities, which depending on their nature, expected resource requirements, or time factors, may be managed either as projects or consulting arrangements. Services will be based on the relevant description of I.T. Professional Services Activities and could include any combination of services described in those aforementioned activities.

Services may be delivered as follows:

- A project staffed and managed by the Services Provider;
- A project partially staffed by the Services Provider and managed by the Services Recipient or the Service Provider;
- An individual resource provided by the Services Provider and managed by the Services Recipient; or
- An integration project staffed by a third party and project managed by the Services Provider.

4.0 ROLES AND RESPONSIBILITIES

STAKEHOLDERS

The stakeholders relating to this Schedule are:

Role	Name	Title	Contact Numbers
Services Recipient	Peter Valiquet	Manager, Customer Service	Office (819) 771-8321 peter.valiquet@enbridge.com
Services Provider	Biju Misra	Manager, Business Applications	Office (416) 495-3976 biju.misra@enbridge.com

The Services Provider will:

- Respond to any Services Recipient Request for Proposal (RFP) in writing within 5 business days for projects 30 person days or less, and within 15 business days for projects over 30 person days.
- Provide resources who are qualified to provide services defined in any agreed-upon project
- Ensure that the requirements for any project are fulfilled through regular review and follow up
- Provide additional services and or information as specified and agreed to in the applicable statement of work

The Services Recipient will:

- Provide detailed business requirements and specifications in order to permit a proposal to accurately reflect the required work and resources
- Provide feedback on the performance and progress of resources assigned to engagements when an engagement is managed by the Services Recipient
- Provide, where necessary, an appropriate working environment for the type of work being performed
- Provide additional services and or information as specified and agreed to in the statement of work

5.0 PERFORMANCE MEASURES

- On-going progress communications as agreed with the Services Recipient
- Project completion quality reviews which include measurement against agreed upon quality expectations as well as costs and time required for delivery
- Specific performance measures, reporting & penalties will be identified in the agreed-upon project.
- Track progress against schedule, budget, scope and quality using the statement of work as the baseline for measurement

6.0 PROBLEM RESOLUTION PROCEDURES

In the event of a failure to resolve any problem within 60 days of the original communication from the Services Recipient, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

7.0 PRICING AND CONDITIONS

Services will be charged at the rates set out in Appendix "A" to this Schedule. These rates will be inflated by 2.1% in 2012 and 2.4% in 2013.

Services provided hereunder shall be charged and payment notices sent, as services are rendered. Payment for services rendered are due in accordance with the schedule set out in the Agreement.

Dated this 24th **day of** March, 2011

APPROVED AS TO FORM ENBRIDGE LEGAL TP

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFERE INC.

Per: _____
JAMIE LEBLANC - GENERAL MANAGER

Per: _____
Lisa Maurice Manager Regulatory Affairs & Budgets

Appendix "A" to Consulting and Professional Services Schedule between Enbridge Gas Distribution Inc. and Gazifere Inc.

Consulting and Professional Services
Hourly Rates

Role	Hourly Bill Rate
Admin Support	$52.00
Desktop Technician	$62.00
Junior Analyst	$84.00
Intermediate Analyst	$94.00
Developer	$94.00
Project Control Administrator	$84.00
Network Administrator	$84.00
Senior Developer	$104.00
Senior Analyst	$104.00
Senior Network Administrator	$104.00
Specialist – All Disciplines	$146.00
Project Manager – Small / Medium Projects	$126.00
Team Leader / Supervisor	$115.00
Architect – All Disciplines	$136.00
Project Manager – Large Projects	$136.00
Manager – Dept / Group	$146.00
Director	$167.00
Contractor Specialist	Cost + $20

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify **IT Infrastructure Services** to be provided to Gazifere Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc.(the "Services Provider").

2.0 TERM

The Services defined in this Schedule are to be provided to the Services Recipient for a period of twenty-four (24) months commencing January 1, 2011 and terminating December 31, 2012. The term of this Schedule may be renewed in accordance with Section 10 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

3.0 IT INFRASTRUCTURE SERVICES

Infrastructure Services encompass a variety of Services. Any services not defined below are out of scope for this Schedule.

The Services Provider will provide Infrastructure Services to the Services Recipient for assets owned or used by Services Recipient. The scope of these services is as follows:

1. **Helpdesk**
2. **Desktop Support**
3. **Managed Desktop**
4. **Equipment Acquisition**
5. **Internet Access**
6. **Server Management**
7. **Installs / Moves / Adds / Changes**
8. **Network Support**
9. **E-mail Service & Support**
10. **Services Governance**

3.1 Helpdesk

Services Provider responsibilities:

- Engage an appropriate phone answering team, on a 7X24X365 basis, to act as a single point of contact for Information Systems problems and routing to Tier 2 teams.
- Assume responsibility for the operation and management of help desk services for Services Recipient
- Call logging and routing of all calls placed with the Helpdesk
- Categorize and prioritize all incidents to ensure they are routed to the appropriate support teams and receive the correct level of attention
- Provision of self service applications (using Remedy) where the SERVICES RECIPIENT user will be able to report an Incident from their desktop instead of placing a call
- Provide a recorded status message to inform callers of any outage effecting a large number of users that is in progress
- Engagement of 2nd level support teams to provide in-depth support on approved hardware and software
- Proactively identify and resolve Problems and Known Errors thus minimizing Incident occurrences
- Minimize the adverse effect on the Service Recipient by Identifying, analyzing and trending reoccurring desktop related problems submitted to the Help Desk
- Provide relevant status information to user who contact the Helpdesk and follow up on all calls to ensure the incident has been resolved to client satisfaction

3.2 Desktop Support

Services Provider responsibilities:

- 2nd Level deskside support/assistance for various hardware and software related problems between 8:00 a.m. and 5:00 p.m. EST, Monday to Friday excluding Services Provider observed holidays
- Warranty repair and replacement for computer equipment and the facilitation of warranty repair for computer equipment covered by another warranty provider
- Services Provider will use commercially reasonable efforts to maintain non-Core Products
- Desktop Security compliance and administration
- Installation of new hardware

3.3 Managed Desktop Service

Services Provider responsibilities:

- Configuring, packaging and deploying all Services Recipient approved desktop software
- Coordinating project-related software deployment to desktops
- Maintaining Services Recipient client code
- Configuring and maintaining desktop and laptop builds
- Maintaining software distribution staging infrastructure

3.4 Equipment Acquisition Service

Services Provider responsibilities:

- Budget process support by providing pricing/availability on current future products and services in order to prepare future year budgets
- Respond to Services Recipient queries regarding product pricing, availability, specifications, order status
- Placing approved orders for all computer technology related equipment or software
- Provide non-biased assistance in gathering and interpreting quotations and deliveries from all vendors
- Shipping and receiving of computer equipment
- Asset tagging of computer equipment
- Forward vendor invoices to Services Recipient for authorization and payment.

3.5 Internet Service

Services Provider responsibilities:

- Provide unlimited access to the Internet at supported desktops and laptops
- Routing of Internet electronic mail to and from Lotus Notes

3.6 Server Management Service

Services Provider responsibilities:

- Engagement of a Tier 2 support team to provide server support 7X24X365
- Warranty repair and replacement for computer equipment and the facilitation of warranty repair for computer equipment covered by another warranty provider
- Provision and maintenance of anti-virus software on Intel servers
- Intel server capacity planning
- Daily operation and administration of the backup and recovery of software and data stored on the servers
- Maintenance and support of the software products and hardware which perform the backups
- Offsite tape vaulting and storage of the backed up information;
- Problem and change management for Intel hardware and operating systems
- Security compliance and administration
- Technical support for Enbridge Gas Distribution standard hardware and standard operating systems
- Performance of system maintenance functions during the maintenance windows or with approval of Service Recipient
- Service Provider will notify Service Recipient of major change requests

3.7 Installs/Moves/Adds/Changes

Services Provider responsibilities:

- Process IMAC requests that have been submitted via the IT Request and contain all required data and which have been previously approved by Service Recipient

- Co-ordination and execution will be scheduled based on the agreed service levels
- Schedule IMACs upon approval of Service Recipient to minimize the impact to the Services Recipient's business operations
- Computer moves to a maximum of one for every two desktop or laptop units per year
- Printer moves and installations
- Co-ordinate IMAC Projects. That is activity involving more than five (5) related End User Workstations. Project will be scoped out as a Professional Services Engagement.
- IMAC calculations will be based on a per technology unit measurement, i.e. one p.c. = one unit, one printer = one unit etc. An IMAC activity, which involves de-installation of a unit (Technology unit i.e. p.c. or printer) at one designated location and the reinstallation of the same unit at another designated location, will be considered to be two IMACs or two units
- Software configuration and/or wiring changes at the PBX

3.8 Network Support Service

Services Provider responsibilities:

- Provide a single point of contact and accountability for managing vendor, contractor, and Services Provider Carrier relationships and contracts. Services Provider Carrier's IT will assume responsibility for :
    - dispatch
    - coordination
    - service escalation
    - issue resolution
    - work order processing
    - contract compliance monitoring
    - vendor billing coordination

- Provide PBX monitoring. Includes proactive monitoring, problem management and change tracking as provided by Services Provider Carrier services.
- Provide Cell Phone support for devices supplied by EGD
- Provide 7 x 24 support for Services Provider Carrier services for required "work-arounds" of existing technologies in specified conditions (i.e. Switch Redirects, etc)
- Provide LAN / WAN monitoring – trends and historical data for re-engineering
- Provision of maintenance and support for VPN network and Firewall
- Provide WAN monitoring. Includes proactive monitoring, problem management and change tracking.
- Provide LAN monitoring. Includes passive monitoring problem management and change tracking
- Provide 2nd level support for related problems and incidents on a rotational 7 x 24 basis
- Perform tracking functions for all problems that require escalation to 3rd parties on a rotational 7 x 24 basis

3.9 E-mail Service & Support

Services Provider will provide:

- Access to EGD email at supported desktops and laptops.
- Support for Blackberry device supplied by EGD
- The provision of support for EGD E-Mail and Calendaring.

3.10 Services Governance

Services Provider will:

- Conduct and attend regular quarterly status and review meetings
- Ensure proper billing and invoicing
- Identify changes in fees based on asset count report
- Review service levels for previous three (3) months
- Review summary of capital projects.

4.0 ROLES AND RESPONSIBILITIES

STAKEHOLDERS
The stakeholders relating to this Schedule are:

Role	Name	Title	Contact Numbers
Services Recipient	Jean-Marie Dallaire	IT Lead/, Co-ordinator	Office (819) 771-8321 jean-marie.dallaire@enbridge.com
Services Provider	Hugh MacMillan	Manager, IT Technical Services	Office (416) 495-6744 Hugh.MacMillan@enbridge.com

The Services Provider will:

1. Assume responsibility for the operation and management of designated Infrastructure services for Services Recipient as outlined in section 3
2. Provide service delivery management accountable through the Service Delivery Manager for all aspects of Service delivery
3. Engage staff with proper training regarding the Services Recipient technical environment and support processes
4. Meet or exceed all performance measures as defined in section 5.0
5. Identify any issues to Services Recipient and work with Services Recipient to resolve such issues
6. Include Services Recipient in the escalation process, and if requested, to escalate service issues directly to Services Recipient staff
7. Provide best effort support of non Enbridge Gas Distribution standard hardware/software.

The Services Recipient will:

1. Provide introductions and orientation to Services Recipient staff as appropriate;
2. Verify asset count every 6 months
3. Make available to Services Provider, personnel to assist to the extent reasonably necessary for Services Provider to provide the services described in this Schedule.
4. Provision all software licenses required in the delivery of these services
5. Provide payment of invoices for servers and or software licenses procured on Services Recipient behalf by Services Provider.
6. Provision of access to Services Recipient's location as required by the Services Provider's personnel to accomplish the services under this Schedule.
7. Ensure that all employees under their jurisdiction will comply with the Statement on Business Conduct and comply with the Services Recipients business processes for approvals
8. Ensure that all facilities are ready for IMAC team, ie. LAN or Voice cable has been installed, electrical power available at location prior to IMAC team coming onsite
9. Packing materials and shipping charges for computer equipment are Services Recipient's responsibility.

5.0 PERFORMANCE MEASURES

Services Provider will deliver to the Services Recipient, upon request or at some mutually agreed to time reporting on the performance of these services to the agreed to service levels tabulated below.

SERVICE LEVEL MEASURE	ATTAINMENT	COMMENTS
HELPDESK		
Telephone Service Factor (TSF)	>=85%	Percentage of phone calls answered by the Tier 1 team in 60 seconds versus total number of incoming calls.

First Call Problem Resolution Rate	>=90%	Percentage of call pertaining to 'Common Off The Shelf Software' (COTSS) handled at the Helpdesk, which are resolved during the client's first call to the Help Desk.
End User Satisfaction	>=80%	Percentage of users who respond to the 'Helpdesk Satisfaction Survey' and were satisfied with the service they received
DESKTOP SUPPORT		
IT Requests	>=90%	Acknowledge Request within 1 business day Schedule date for installation within 3 business days
Resolution of Low Priority Incidents	>=90%	Resolve within 3 Service Days
Resolution of Medium Priority Incidents	>=90%	Resolve within 8 hours
MANAGED DESKTOP SERVICES		
Installation of packaged software.	>=90%	Installation of packaged software via the software distribution system within 1 Business Day).
Packaging of new software	>=90%	Packaging of new software will be completed within 5 business days from the completion of the required forms
EQUIPMENT ACQUISITION		
Response time for inquiries	>=90%	Response to inquiries for pricing, availability and product information answered within 2 Service Days (No Report)
Standard Hardware and Software	>=90%	All hardware and software will be ordered within 3 business days from the completion and approve of IT Request. (Delivery date is subject to Vendors SLAs)
INTERNET ACCESS, SERVER MANAGEMENT and NETWORK SUPPORT		
Resolution of Medium Priority Incidents	>=90%	Resolve within 8 hours
Resolution of High Priority Incidents	>=90%	Resolve within 4 hours
Resolution of Urgent Priority Incidents	>=90%	Resolve within 2 hours
Availability	>=99%	The Internet, Production Network and Production Servers will be available 99% of the time (calculated over 1 year). * Scheduled outages are not included in this calculation

INSTALLATION/MOVES/ADDS/CHANGES		
Install, Moves, Adds, Changes (IMACs) of less than 5 Telephone Sets	>=90%	Acknowledge Request within 1 business day Schedule a date for installation within 3 business days Complete installation within 5 business days
Install, Moves, Adds, Changes (IMACs) of greater than 5 Telephone Sets	N/A	The Service Level for requests of a group of 5 or more IMACS will be agreed between Services Provider and Services Recipient at the time of planning the IMACs.

6.0 PROBLEM RESOLUTION PROCEDURES

In the event of a failure to resolve any problem within 60 days of the original communication from the Services Recipient, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

7.0 PRICING AND CONDITIONS

The estimated annual fee for Desktop Services described in this Schedule shall be $185,437.00 in 2011. This is based on a monthly per device cost of $187.99 for 80 devices (Desktops/Laptops/Intel Servers) and $51.73 for 8 AP Mobile devices. These rates will be inflated by 2.1% in 2012.

The foregoing is based on an annual calendar year forecast of expected service requirements reasonably determined by the Services Provider. The Services Provider reserves the right to revise this estimate in the event that the services rendered are significantly more or less than the estimated amount.

The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately and agreed upon in advance with the Services Recipient.

Payment for services rendered is due in accordance with the schedule set out in the Agreement.

The Services Recipient reserves the right to terminate this agreement subject to sixty days (60) written notification being provided to the Services Provider. Upon termination of the agreement the book value of any assets in the possession of the Services Recipient will become due and payable to the Services Provider.

Dated this 11th **day of** May, 2011

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law & Information Technology

GAZIFERE INC.

Per: _____
Jamie LeBlanc
General Manager

Per: _____
Lise Manuel
Manager Regulatory Affairs & Budgets

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Legal, Corporate Secretarial, and Executive Services*** ("Services") to be provided to Gazifere Inc. (hereinafter referred to as the "Services Recipient") by Enbridge Gas Distribution Inc. (hereinafter referred to as the "Services Provider").

The Services defined in this Schedule are to be provided to the Services Recipient for a period of three years, commencing January 1, 2011 and terminating December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

Corporate Secretarial Services: The basic principles of corporate secretarial practice are related to managing contingencies under which board of directors decision-making occurs, compliance with statutes and regulations under which a company must operate and the promotion of good corporate governance procedures. The Services Provider will maintain current knowledge with respect to the legislation, regulations and applicable constating documents which govern the Services Recipient and its subsidiaries. The Services Provider will ensure that all affairs of the applicable Boards of Directors and Board Committees (including organization of Partnership, Board and Committee meetings) are administered in accordance with the principles of good corporate secretarial practice.

Legal Services: The Services Provider will provide legal services to the Services Recipient and its identified business units and subsidiaries on an as required basis. Services will be provided directly through the use of internal resources and, with the approval of the Services Recipient, external legal counsel as required. The Services Provider will be responsible to supervise the quality and cost of outside legal services in such instance.

Executive Services: Certain executives of the Services Provider, as appointed, will act as directors, officers, and/or advisors to the Services Recipient from time to time. These services will be provided in compliance with all applicable laws and regulations governing the duties of directors and officers to business corporations.

3.0 ROLES AND RESPONSIBILITIES

Corporate Secretarial Services

The Services Provider will, as required:

- ensure a proper information flow to the applicable Boards and Committees;
- provide legal and procedural advice to the Chairs, Boards and Committees as required;
- organize and prepare shareholders' and board meetings, including the settlement of meeting dates and agendas and preparation and approval of all Board minutes;
- ensure compliance with applicable corporate and securities legislation/regulations, including statutory reporting and filings;
- maintain corporate records and documents on behalf of the Services Recipient;
- act as agent for the purposes of receipt of all legal and official documentation and notices served on the Services Recipient; and
- address share, shareholder and shareholder register issues as required.

Legal Services

The Services Provider will, as requested:

- identify laws and statutes which impact upon the Services Recipient's daily and routine business decisions and acquainting management in a general manner with these laws;
- identify risks and, to the extent possible, suggesting alternative courses of action;
- identify risks in a positive manner so that management can make informed decisions;
- promote compliance with laws applicable to the Services Recipient and its employees;
- provide policy advice and develop forms of standard documentation (e.g. standardized services agreements) in appropriate circumstances;
- provide legal advice/opinions and related business advice to the Services Recipient, its managers, employees and subsidiaries;
- prepare, review and revise commercial agreements;
- manage external legal services; and
- interpret key statutory or regulatory provisions affecting the Services Recipient and its businesses.

Executive Services

Appointed executives of the Services Provider will, as required:

- attend and conduct Board of Director and Committee meetings;
- oversee the business affairs of the Services Recipient; and
- advise on other miscellaneous business and governance matters.

The Services Recipient will:

- pay for the Services as rendered within the time periods set out in the Agreement; and
- ensure that all instructions and information relevant to the Services Provider's assignments are provided to the Services Provider on a timely basis.

4.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the Services should be brought to the attention of the Vice President, Gas Distribution Law and Deputy General Counsel of the Services Provider if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

5.0 PRICING AND CONDITIONS

During the term of this Schedule, the hourly service rates shall be the following:

(a) $280.00 per hour for all services provided by the Vice President, Gas Distribution Law and Deputy General Counsel;

(b) $280.00 per hour for all services provided by the Senior Legal Counsel;

(c) $120.00 per hour for all services provided by the Law Clerk; and

(d) $280.00 per hour for all executive services provided.

The rates shall be increased by 2.1% in 2012 and 2.4% in 2013. The Services Provider will ensure that all Services (either through the Services Provider's own resources or by external counsel) are provided in accordance with the terms of this Schedule. The Services Recipient acknowledges that some consultation with external legal advisors (law firms) will be necessary in connection with the routine delivery of the legal services. However, the Services Provider will ensure that the Services Recipient's approval is obtained prior to the retention of external legal advisors for significant files.

The Services Recipient will be charged for actual time spent by the Services Provider, as determined by time dockets, for providing the Services. Except for services provided by external counsel, payment notices for Services will be sent to the Services Recipient at the end of each calendar quarter and payments are due in accordance with the schedule set out in the Agreement. All amounts charged to the Services Recipient by external legal counsel (including both fees and disbursements) shall be paid in full by the Services Recipient on a timely basis.

The Services Recipient will be required to reimburse the Services Provider for reasonable out of pocket expenses incurred by the Services Provider in accordance with the Agreement.

Dated this 24th **day of** March, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFÈRE INC.

Per: _____

Jamie LeBlanc - General Manager

Per: _____

Lise Hamel Regulatory Affairs & Budget

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. (the "Agreement").

1.0 PREFACE

This Schedule is intended to identify ***Regulatory Services*** to be provided to Gazifère Inc. (the "Services Recipient"), by Enbridge Gas Distribution Inc. (the "Services Provider").

The services defined in this Schedule are to be provided to the Services Recipient for a period of three years (03), commencing January 1, 2011 and ending December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The service functions provided under this schedule are regulatory policy/strategy advice, business and rates analysis, case management support and legislative/regulatory issues tracking. The Services Provider will maintain current knowledge with respect to the legislation, regulations, regulatory decisions and other industry information relevant to the Services Recipient.

The Services Provider will supply quality, cost-effective regulatory services using internal resources and, with the approval of the Services Recipient, external legal counsel and consultants as required. The Services Provider will be responsible to supervise the quality and cost of outside services so as to support and assist the Services Recipient in attaining its regulatory objectives.

The Services Recipient shall provide the Services Provider with all requested supporting documentation required to conduct the Working Cash Allowance, Fully Allocated Cost of Service Study and Rate Design proposal.

Services will be provided on a proactive basis by identifying potential regulatory risks and taking steps to counter these positions by supporting the Service Recipient's lobbying efforts and/or drafting submissions to the Régie de l'énergie.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider is responsible for the following:

Policy and Strategic Services/Business and Rates Analysis

- Provide the Services Recipient with the Working Cash Allowance, Fully Allocated Cost of Service study and associated Rate Design proposal for a given Test Year.
- Evidence supporting the above will also be provided to the Services Recipient. The Services Provider will generate or give curves for the Test Year and provide revenue forecasting for customers taking service pursuant to Rates 1 and 2.

- The Services Provider will provide support in the Regulatory Closing of the Books process as it relates to determining the actual Working Cash requirement. The Service Provider will also generate the pass-on in gas costs unit rates, by components, if applicable.

Case Management and Support Services

- Provide the Working Cash Allowance in time to meet the Phase 1 regulatory timetable. The Cost Allocation and Rate Design evidence will be submitted to Gazifère 10 business days after receiving all finalized supporting documentation required to perform the studies.
- The Services Recipient will provide all supporting documentation for the Cost allocation and Rate Design to the Services Provider at least 10 business days before the regulatory deadline.
- Evidence supporting working cash allowance, fully allocated cost of service study and associated Rate Design proposal will be to the Services Recipient.

Regulatory and Legislative Issues Tracking Services

- As required.

4.0 PERFORMANCE MEASURES

The evidence shall be submitted within the prescribed deadlines. Modifications to the original evidence shall be minimal.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the regulatory services should be brought to the attention of the designated representative of the Services Provider if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

During the Term of this Schedule, the services described above and any additional regulatory service will be charged at the following hourly rates:

	Effective Jan 1/11	**Effective Jan 1/12**	**Effective Jan 1/13**
Director/Senior Manager (Case Management)	**$245**	$250	$256
Manager/Senior Analyst (Strategy/Policy Advice and Business & Rates analysis)	**$192**	$196	$201
Supervisor & Analyst (Case Administration, Case Monitoring, Regulatory Activity Reports, Legislation/Regulation Tracking)	**$149**	$152	$156
Administration (Admin. Support)	**$129**	$132	$135

The estimated dollar amount budgeted for this service in 2011 is $20,000. This rate will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.

Service rates may be changed in subsequent years upon at least 30 days notice from the Services Provider to initiate discussions in good faith with the Services Recipient. Payment notices for services provided under this Schedule shall be submitted to the Services Recipient once each calendar month and are payable in accordance with the schedule set out in the Agreement. The Services Provider shall ensure that all services delivered hereunder (either through the Services Provider's own resources or by external counsel) are provided in accordance with the terms of this Schedule.

The Services Recipient will be required to reimburse the Services Provider for reasonable out of pocket expenses incurred by the Services Provider in accordance with the Agreement.

All amounts charged to the Services Recipient by external legal counsel and external consultants (including both fees and disbursements) shall be paid in full by the Services Recipient on a timely basis.

Dated this 24th **day of** March, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM ENBRIDGE LAW TP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law & Information Technology

GAZIFÈRE INC.

Per: _____
Jamie LeBlanc – General Manager

Per: _____
Vice General Manager Regulatory Affairs & Budgets

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Risk Management Services*** to be provided to Gazifère (the "Services Recipient"), by Enbridge Gas Distribution Inc. (the "Services Provider").

The services defined in this Schedule are to be provided to the Services Recipient for period of three years commencing January 1, 2011 and ending December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with:

1a.) Management of Services Recipient's Insurance Program by ensuring appropriate insurance coverage, or other risk mitigation techniques, are in place. Also, provide certificates evidencing such insurance as required by legislation or upon request;
1b.) Maintenance of information related to insurance and CSST (Commission de la Sante et de la Securite du Travail) coverage for all contractors used by the Services Recipient based on established insurance parameters;
1c.) Management of Vehicle Insurance and related claims handling; and

2a.) Management of all third party liability claims handling through both internal adjusters and external service providers, including the investigation and settlement of all incidents;
2b.) Management of all first party property damage and liability claims through both internal adjusters and external service providers, including the investigation and settlement of all incidents.

3.0 SERVICE LEVELS

The Services Provider will:

- ensure the existence and availability of a constantly improving comprehensive risk management program designed to effectively reduce business risks to acceptable levels;
- ensure risk management services are provided in a timely manner and that reports are issued within two weeks or as negotiated prior to the commencement of services;
- ensure appropriate insurance coverage, or other risk mitigants, are in place 100% of the time in order to support the business operations of the Services Recipient;
- ensure appropriate coverage for contractors identified by the Services Recipient is in place;
- respond to the notification of all claims within 24 hours; and
- provide monthly status updates of claims to Service Recipient.

The Services Recipient will:

- provide all information critical to risk management services within 2 days or as agreed upon by both Service Provider and Service Recipient;
- communicate all new ventures and programs in writing in advance of program commencing;
- provide all information related to insurance underwriting submission as identified by the Services Provider within 2 weeks of receiving a written request;
- identify all contractors to the service provider and any changes in contractor status;
- notify service provider of any incidents, claims, and vehicle accidents by phone and in writing within 24 hours; and
- provide all requested information related to both first party and third party incidents within 2 days of request.

4.0 PERFORMANCE MEASURES

The delivery of the services will be measured by:

- risk management findings and reports being produced and distributed within the negotiated timeframe 100% of the time;
- 100% of Services Recipient appropriate insurance coverage requirements, as well as its identified contractors appropriate insurance requirements, being placed depending on the breath and level of coverage as agreed to by both Services Provider and Services Recipient in advance; and
- 100% of all claims being responded to within 24 hours of notification. Insurers' subrogation claims to be assessed on a case by case basis.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the services identified in this schedule should be brought to the attention of the Manager, Risk Management if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The services described in this Schedule shall be charged at an hourly rate of $94.00 in 2011. The 2011 rate will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.

The estimated fees for services described in this Schedule shall be $7,520 in 2011. The foregoing fees are based on an annual forecast of expected service requirements reasonably determined by the Services Provider and will be charged in four equal installments on a quarterly basis. This amount includes an estimate of reasonable out of pocket expenses payable in accordance with the Agreement and accordingly no additional amounts will be charged to the Services Recipient on account of out-of-pocket expenses. The Services Provider reserves the right to revise this estimate in the event that the services rendered are significantly more or less than the estimated amount. The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately by and agreed upon in advance with the Services Recipient. Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payments for services rendered are due in accordance with the schedule set out in the Agreement.

Dated this 24th **day of** March, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

Per: _____ Narin Kishinchandani
Vice President, Finance

Per: _____ Mark R. Boyce
Vice President, Law & Information Technology

GAZIFÈRE INC.

Per: _____
JAMIE LE BLANC - GENERAL MANAGER

Per: _____
Assistant Manager Regulatory Affairs & Rates

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify **Strategy, Research and Planning** services to be provided to Gazifère (the "Services Recipient") by the Strategy, Research and Planning department of Enbridge Gas Distribution Inc. (the "Services Provider").

The services defined in this Schedule are to be provided to the Services Recipient for a period of three years (03), commencing from January 1, 2011 and ending December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with the following:

1. Meter Reading Degree Day Tracking Report. The file will be submitted by the 5th business day of the month.

2. Degree Day forecasts. The forecasts and supporting memo will be provided once per year in March for the following fiscal year. The forecasts will be based on the 20-year trend methodology currently in place, using the latest data available at the time the forecasts are generated. Any change in methodology required by the Services Recipient must be first negotiated with the Services Provider.

3. Average Use model. The forecasts and supporting memos for residential and commercial average use will be provided once per year by mid-April for the following fiscal year. Any updates will include the latest data available at the time the forecasts are generated. Both normalized and un-normalized forecasts will be provided.

4. Seasonality factor model. The forecasts and supporting memo will be provided once per year in March for the following fiscal year. Any updates will include the latest data available at the time the forecasts are generated.

5. Contract Demand. The forecasts and supporting memo will be provided once per year in May for the following fiscal year. Any updates will include the latest data available at the time the forecasts are generated.

6. UUF. The forecasts and supporting memo will be provided once per year for the prior fiscal year. Any updates will include the latest data available at the time the forecasts are generated.

7. Financial analysis required for regulatory filings

8. Feasibility guidelines and capital requisitions

9. Strategic planning (LRP)

10. Special studies

For all other requests not outlined above, the timelines for data requirements to be provided by the Services Recipient, and for the deliverance of a final product by the Services Provider, must be negotiated in advance. For consideration of any other such analysis, a minimum requirement of 10 business days (2 weeks) after the receipt of the correct input data is mandatory.

3.0 SERVICE LEVELS

The Services Provider will:

- Ensure the data used in all models, forecasts, and analysis is timely and accurate;
- Answer any questions related to the methodologies, or outputs.

The Services Recipient will:

- Provide all information critical to the processes of the deliverables listed above at least 10 business days (2 weeks) prior to delivery. The time frames listed above are for reference only, however, final delivery cannot be provided in less than 10 business days.
- Communicate timelines and deliverable specifics clearly and in a timely fashion.
- Provide any other requested information required to enhance or improve the services provided;

For all other requests not outlined in Section 2.0 above, the timelines for data requirements to be provided by the Services Recipient and for the deliverance of a final product by the Services Provider must be negotiated in advance. For consideration of any other such analysis, a minimum requirement of 10 business days (2 weeks) after the receipt of the correct input data is mandatory.

4.0 PERFORMANCE MEASURES

Performance is deemed acceptable if the Services Recipient approves the deliverable within a specified timeframe. To that effect, it is the responsibility of the Services Recipient to ask any questions, to make any suggestions or comments, or to otherwise submit any inquiries within 10 business days (2 weeks) after final delivery. If no such feedback is obtained, it is assumed the deliverable has been accepted. The Services Provider will ensure that all models, forecasts, and/or supporting memos are as accurate as possible given the quality of data provided.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the services identified in this schedule should be brought to the attention of the Director, Strategy, Research and Planning if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The fees for services described in this Schedule shall be as follows:

Analytical activities will be charged at the following hourly market based rates of:

Service Provider	Years (in $/HR) 2011	2012	2013
Market Analyst / Financial Analyst	$110	$112	$114
Advisor	$140	$142	$145
Manager	$194	$198	$202
Director, Strategy, Research & Planning	$235	$240	$245

The 2011 budgeted amount is $14,800. All 2012 and 2013 rates & amounts have been derived by applying an inflation factor of 2.1% and 2.4% respectively to the 2011 market rate. The costs of goods and services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately by and agreed upon in advance with the Services Recipient. Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payments for services rendered are due in accordance with the schedule set out in the Agreement.

Non-labour related costs such as materials and supplies, transportation, and travel will be billed (if applicable) to the Services Recipient.

Dated this 24th **day of** March, 2011

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM ENBRIDGE LAW TP

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law & Information Technology

GAZIFÈRE INC.

Per: _____

JAMIE CORBEANE - GENERAL MANAGER

Per: _____

Lisa Maurice Manager Regulatory Affairs & Strategy

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. DATED JANUARY 1, 2011 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Taxation Services*** to be provided to Gazifere Inc. (hereinafter referred to as the "Services Recipient") by Enbridge Gas Distribution Inc. (hereinafter referred to as the "Services Provider").

The Services defined in this schedule are to be provided to the Services Recipient for a period of three years (03), commencing January 1, 2011 and terminating December 31, 2013. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Any prior schedule under this Agreement governing the same Services as those set out is hereby terminated and superceded by this Schedule from the date of this Schedule onward.

2.0 DEFINITION OF SERVICES

The Services Provider agrees to provide the Services Recipient with:

- Preparation and filing of annual federal and provincial corporate income and capital tax returns for the Services Recipient from the accounting systems of the Services Recipient and information provided by the Services Recipient, including the review of information prepared by the Services Recipient to ensure compliance with Federal and Provincial Income and Capital Tax Law;
- Provide advice and assistance re: matters pertaining to annual income tax and capital tax accounting provisions for the Services Recipient;
- Provide general tax advice to the Services Recipient including responses to general income, capital and commodity tax questions from the Services Recipient but excluding advice on proposed Services Recipient acquisitions and new businesses; and
- Assist federal and provincial income, capital and commodity tax audits of the Services Recipient and negotiate issues arising in the course of such audits.
-

3.0 ROLES AND RESPONSIBILITIES

The Services Provider is responsible for the following:

- Recommend to and obtain approval of the Services Recipient of filing position on potential contentious tax issues within the time frame agreed upon at the time the issue is identified;
- Provide the Services Recipient with completed tax returns for the company at least one week prior to the filing date for each return;
- File all annual income tax returns by their due dates;
- Provide timely and accurate responses to general tax questions within the time frame agreed upon when question is asked; and
- Review proposed and issued tax assessments and recommend to Services Recipient, at least 1 month before deadline for filing a notice of objection, either acceptance and payment or commencement of litigation.

The Services Recipient is responsible for the following:

- Provide Taxation with unconsolidated financial statements and schedules and information required for accurate preparation of tax returns at least 2 months prior to the filing date for the returns;
- Provide Taxation access to all systems necessary to enable Taxation to provide the above services to the Services Recipient;
- Disclose to Taxation all potential tax issues as they arise; and
- Identify all dates to the Services Provider for monthly and annual reporting requirements at least 2 weeks in advance of any scheduled date.

4.0 PERFORMANCE MEASURES

- Preparation of tax returns by filing due dates 100% of the time.
- All other service levels will be met 90% of the time.

The Services Provider will meet semi annually, or as requested by the Services Recipient, to review the performance of the Services Provider from the last such meeting including assessment of the value added, risk areas, responsiveness to Services Recipient concerns, etc. Action steps and follow up will be identified where possible.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the Taxation Services should be brought to the attention of the Manager, Tax Services of the Services Provider if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures set forth in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

The services described in this Schedule shall be charged at an hourly rate of CAD $235.00. The 2011 rate will be adjusted by an inflation factor of 2.1% in 2012 and 2.4% in 2013.

The estimated fees for services described in this Schedule are estimated to CAD $7,850.00 per year. The foregoing is based on an annual calendar year forecast of expected service requirements reasonably determined by the Services Provider. This annual forecast may be adjusted in accordance with Section 7 of the Agreement. This amount included an estimate of reasonable out of pocket expenses payable in accordance with Section 6 of the Agreement and accordingly no additional amounts will be charged to the Services Recipient on account of out-of-pocket expenses. The Services Provider will notify the Services Recipient, as promptly as reasonable in the circumstances, of expected variances from the annual forecast in excess of 10%. The parties will meet promptly to discuss the reasons and establish whether the annual forecast should be revised.

The costs of goods or services from third parties obtained to address special technical requirements or fulfill a special request of the Services Recipient will be borne separately by and agreed upon in advance with the Services Recipient.

Dated this 24th day of [illegible], 2011

Enbridge Gas Distribution Inc.

APPROVED AS TO FORM
ENBRIDGE LAW JP

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Mark R. Boyce
Vice President, Law & Information Technology

Gazifere Inc.

Per: _____
JAMIE LE BLANC – GENERAL MANAGER

Per: _____
Lead Planning Manager Regulatory Affairs & Budgets

SERVICES SCHEDULE TO THE AGREEMENT DATED JANUARY 1, 2011 BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFÈRE INC. (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Key Account Management Services*** to be provided to Gazifere Inc. (the "Services Recipient"), by Enbridge Gas Distribution Inc. (the "Services Provider") as a transitional measure to repatriating some or all of these services to the Services Recipient as soon as practicable to meet code requirements.

The services defined in this Schedule are to be provided to the Services Recipient only until a plan to repatriate the services has been determined, at which time the parties will establish a new schedule to define the revised scope of services. This schedule will expire December 31, 2013 if not terminated earlier. The term of this Schedule may be renewed in accordance with Section 9 of the Agreement. Notwithstanding the provisions of Section 23 of the Agreement, the Services Provider may assign its rights and obligations under this Schedule to an affiliate of the Services Provider upon the delivery of written notice thereof to the Services Recipient.

2.0 DEFINITION OF SERVICES

The Services Provider will provide a variety of Key Account Management activities. Service levels have been identified in section 3.0 of this Schedule. Additional services may be provided at the written request of the Services Recipient and will be subject to acceptance to by the Services Provider.

3.0 SERVICE LEVELS

The Services Provider will:

- Negotiate large volume distribution contracts and direct purchase agreements (when applicable) with identified Key Account customers, which will effectively meet the requirements of the customers as applied in the Rate Handbook.
- Provide support to ensure compliance of all contractual agreements with end use customers.
- Provide ongoing support to contracted large volume contract customers to assess the impact and develop strategies to maximize opportunities or reduce risk with respect to any Provincial or Federal regulated decisions.
- Provide ongoing support to continue to build on existing long term relationships as well and to develop new relationships. This would include responding to any large volume billing or related inquiries.
- Provide support during periods of Curtailment or Emergency to ensure all requests are effectively communicated to customers.

- When requested, develop a grassroots volumetric forecast for all large volume contract customers. In addition, on a monthly basis, provide a volumetric analysis and report all major variances.

The Services Recipient will:

- Reimburse the Services Provider within the time periods set out including reimbursement for all travel, accommodation and reasonable entertainment expenses incurred in conducting business.

4.0 PERFORMANCE MEASURES

The Services Provider will:

- Present all contracts requiring regional signature to Assistant General Manager, Gazifere Inc. a minimum of fifteen days prior to the commencement date of the contract.
- The Services Provider will provide a detailed report in support of all charges, when requested by the Services Recipient.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the Services Provider should be brought to the attention of the Manager, Key Accounts if they cannot be resolved with the staff directly involved. Failing resolution, the Problem / Conflict Resolution procedures identified in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

- The services described in this Schedule shall be charged monthly as services are rendered at an hourly rate as identified in the following Schedule of Prices. Payments for services rendered are due in accordance with the schedule set out in the Agreement.
- Schedule of Prices

  Effective January 1, 2011 the hourly service rates shall be the following:

  (a) $90.00 per hour for all services provided by the Account Executive.
  (b) $105.00 per hour for all services provided by the Manager, Key Accounts.
  (c) $65.00 per hour for all services provided by the Administrative Support Staff.
  (d) $115.00 per hour for all services provided by the Manager Direct Purchase

The above rates will be adjusted by an inflation factor of 2.1% for 2012 and an additional 2.4% for 2013.

Dated this 8th **day of** April, 2011.

ENBRIDGE GAS DISTRIBUTION INC.

APPROVED AS TO FORM
ENBRIDGE LAW TP

Per: _____

Narin Kishinchandani
Vice President, Finance

Per: _____

Mark R. Boyce
Vice President, Law &
Information Technology

GAZIFÈRE INC.

Per: _____

JAMIE LEBLANC
GENERAL MANAGER

Per: _____

DEBBIE BRAULT
OPERATIONS MANAGER

SERVICES SCHEDULE TO THE INTERCORPORATE SERVICES AGREEMENT BETWEEN ENBRIDGE GAS DISTRIBUTION INC. AND GAZIFERE INC. DATED January 1, 2012 (the "Agreement")

1.0 PREFACE

This Schedule is intended to identify ***Public and Government Affairs services*** to be provided to Gazifere Inc. (the "Services Recipient") by Enbridge Gas Distribution Inc. (the "Services Provider").

The Services defined in this Schedule are to be provided to the Services Recipient for a period of two years, commencing January 1, 2012.

2.0 DEFINITION OF SERVICES

The Services Provider will develop and assist in the implementation of government, communication and community relations strategies for the Services Recipient in consultation with the project management team. Public and Government Affairs will also manage external Public Relations consultants providing support on initiatives to support the business as required.

The detailed planning for individual initiatives will be performed prior to commencement of the design, and will include a review of the planned scope, objectives and timeframe with Services Recipient management.

3.0 ROLES AND RESPONSIBILITIES

The Services Provider is responsible for the following:

- Consult with management of the Services Recipient prior to finalization of the government, communication community initiatives to ensure that the needs of the Services Recipient will be adequately addressed. Subsequently, if modifications to the initiatives are required, have on-going discussions with management to ensure all significant requirements continue to be adequately addressed

- Act in project leadership role for all government, communication and community initiatives developed to support the needs of the Services Recipient

- Manage any external public affairs agency that provides support to help meet business objectives

- Liaise with the Services Recipient and provide local support/initiative coordination for Corporate initiatives which include the Services Recipient in their implementation

- Interact with the Services Recipient to present proposals and receive approvals required for government, communication and community initiatives

- Work with the Services Recipient in finalizing the detailed scope, objectives and timing for individual initiatives to ensure requirements are fulfilled in an optimal manner that meet the timing and implementation constraints of the Services Recipient

- Participate in regular planning/update sessions of the Services Recipient to ensure ongoing understanding of needs and requirements

The Services Recipient is responsible for the following:

- Ensure Management participation/input in the development of government, communication and community strategies and subsequent review of initiatives developed in support of those strategies

- Make available the necessary and appropriate level of internal or external resources on a timely basis to act as extended team members/expert sources to develop the initiatives to support of the business strategies

- Provide regular information/access to information requested by the Services Provider to assess needs and determine support requirements

4.0 PERFORMANCE MEASURES

Services Provider will meet all agreed timeframes and deliverable quality. The Services Provider will meet with the Services Recipient semi-annually or as otherwise requested by either party, to review the performance of the Services Provider and to document any agreed upon changes or revisions to the services outline herein.

5.0 PROBLEM RESOLUTION PROCEDURES

Any concerns with respect to the performance of the Public & Government Affairs team should be brought to the attention of the Director of Public and Government Affairs. Concerns will be addressed by the Director of Public and Government Affairs with the VP, Regulatory & Public Affairs of Enbridge Gas Distribution Inc. Failing resolution, the Problem/Conflict Resolution procedure set out in the Agreement will be followed.

6.0 PRICING AND CONDITIONS

An average hourly rate of $214.41 shall apply to services rendered. The fees for services described in this Schedule will be dependent on services and scope of the project required. The foregoing fees will be pro-rated and charged monthly. The Services Provider reserves the right to revise the project estimate in the event that the services rendered are significantly more or less than the estimated amount.

Services provided hereunder shall be charged, and payment notices sent, as services are rendered. Payments for services rendered are due in accordance with the schedule set out in the Agreement.

Dated as of the 1st day of January, 2012.

Gazifere Inc.

Per: _____ JAMIE MILNER DIRECTOR

Per: _____ ARUNAS PLEČKAITIS DIRECTOR

APPROVED AS TO FORM ENBRIDGE LAW

Enbridge Gas Distribution Inc.

Per: _____
Narin Kishinchandani
Vice President, Finance

Per: _____
Glenn Beaumont
Senior Vice President, Operations

OPINION DE LA RÉGIE

La Régie accepte les charges projetées résultant du programme de rémunération au rendement destiné aux employés. Cependant, elle s'interroge sur le mode de fonctionnement et d'établissement de la rémunération au rendement.

La Régie est, par ailleurs, préoccupée par le fait qu'une partie de la rémunération au rendement versée aux employés à même les revenus générés par les tarifs de Gazifère, soit conditionnelle à la performance d'Enbridge.

La Régie demande à Gazifère de justifier, dans le prochain dossier tarifaire, le fait que la rémunération au rendement des employés de Gazifère soit rattachée, en partie, au rendement d'Enbridge.

3.4.3 CHARGES ENTRE COMPAGNIES AFFILIÉES

POSITION DE GAZIFÈRE

Gazifère a retenu Deloitte Consulting (Deloitte) comme expert indépendant pour répondre à la demande de la Régie de réévaluer la nécessité de certains services obtenus des compagnies affiliées et d'effectuer les analyses nécessaires afin de s'assurer du moyen le plus économique de les obtenir[20].

Les analyses de Deloitte, présentées en deux rapports, portent sur les charges suivantes :

Faisant l'objet du premier rapport :

- 101 600 $ facturé par Enbridge pour EFS;
- 100 600 $ facturé par Enbridge Commercial Services Inc. (ECS) pour l'allocation du coût en capital d'EFS;
- 183 000 $ facturé par EGD pour support aux usagers, entretien des applications et service d'administration du réseau;

Faisant l'objet du deuxième rapport :

- 132 833 $ pour le système EnVision[21].

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[20] Pièce GI-4, document 8.1, page 7, NS, volume 4, 15 février 2005, page 10, donnant suite à la décision D-2000-48, dossier R-3430-99, 29 mars 2000.

[21] Pièce GI-4, document 8.1, page 7, NS, volume 4, 15 février 2005, page 10.

Les conclusions du premier rapport sont les suivantes :

- il existe un *Inter-Corporate Services Agreement* entre EGD et Gazifère et tous les services sont décrits adéquatement dans des documents, sauf pour les services fournis par ECS et Enbridge;
- tous les services sont nécessaires pour que Gazifère puisse exploiter son entreprise et servir ses clients;
- toutes les charges sont raisonnables[22].

Deloitte est d'avis que les critères d'allocation présentement utilisés pour ces services sont adéquats et l'utilisation d'autres critères n'aurait pas d'impact significatif sur les coûts.

Deloitte conclut que Gazifère reçoit un service à un coût juste et raisonnable en tenant compte des économies d'échelle qui ne pourraient pas être atteintes dans le cadre de l'application du principe d'isolement (stand-alone). De plus, Deloitte exprime le fait que tous les facteurs d'allocation de coûts pour ces services ont une base et une causalité[23].

De l'opinion de Deloitte, les coûts satisfont donc les critères établis par la Régie.

Deloitte note également qu'Enbridge charge les coûts à Gazifère uniquement sur la base des coûts sans y ajouter de rendement[24].

Le deuxième rapport de Deloitte concerne les coûts pour le système EnVision au montant de 132 833 $. EnVision est composé notamment du sous-système Work and Assets Management (WAMS) et l'un de ses objectifs est de servir au remplacement de plusieurs systèmes destinés à la gestion du travail et des actifs, notamment le système Legacy[25].

Gazifère espère obtenir plusieurs avantages de l'utilisation du système EnVision. Ceux-ci sont en partie le résultat d'une fonctionnalité du début à la fin et du fait de l'intégration du système. Il est prévu que ces avantages seront réalisés une fois que seront complétés la courbe d'apprentissage initiale et les activités de post implantation[26].

La conclusion de ce rapport est que les services donnés par EnVision à Gazifère sont nécessaires et cruciaux pour qu'elle puisse exploiter son entreprise et servir ses clients. Les

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[22] NS, volume 4, 15 février 2005, pages 12 à 16.
[23] NS, volume 4, 15 février 2005, pages 14 et 15.
[24] NS, volume 4, 15 février 2005, page 29.
[25] Pièce GI-4, document 7.6, pages 1, 4, 5 et 6.
[26] Pièce GI-4, document 7.6, page 12.

coûts de ces services sont justes et raisonnables et la charge pour EnVision est totalement basée sur des prix de marché et allouée entre EGD et Gazifère selon le nombre de clients.

De plus, Deloitte conclut qu'il serait difficile pour Gazifère, dans le cadre de l'application du principe d'isolement, d'obtenir les mêmes services sur le marché à un coût compétitif[27].

Selon Deloitte, les coûts relatifs au système EnVision satisfont les critères établis par la Régie.

Gazifère précise que pour l'année témoin 2004-2005, les charges d'exploitation reliées à l'utilisation de WAMS se chiffrent à 132 833 $. Les charges résultant du système EnVision, autres que les charges reliées à l'utilisation de WAMS, comprennent le salaire d'un superviseur à 50 % à un coût de 30 000 $. Aucun autre coût opérationnel ou coût en capital n'a été prévu pour l'année témoin 2004-2005 résultant du système EnVision. Elle ne connaît pas à ce moment-ci les montants qui lui seront facturés pour l'utilisation de WAMS dans les années à venir[28].

Gazifère est d'avis qu'éventuellement elle devrait voir certains gains de productivité mais, pour le moment, il est très difficile de les prévoir parce qu'elle en est au stade de l'implantation et qu'il y a encore des problèmes. Une fois que le système sera rodé, la clientèle sera servie beaucoup plus rapidement et les employés bénéficieront d'une meilleure planification du travail[29].

L'allocation des coûts pour les services fournis par Enbridge a débuté seulement en janvier 2003, même si Gazifère bénéficiait déjà de ces services[30]. Gazifère invoque le principe d'isolement pour justifier la raisonnabilité des coûts et maintient que si elle devait aller sur le marché pour se payer les mêmes services, les coûts en seraient supérieurs[31].

En ce qui a trait aux charges d'administration facturées par Enbridge, Gazifère mentionne que ces coûts, couvrant les services de gestion, ressources humaines, trésorerie et s'élevant à 351 800 $, n'étaient pas facturés de 1999 à 2002[32].

Gazifère bénéficie financièrement des services centralisés offerts par Enbridge et ce, de deux manières:

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[27] NS, volume 2, 18 janvier 2005, page 104.
[28] Pièce GI-19, document 3, page 1.
[29] NS, volume 2, 18 janvier 2005, page 135.
[30] NS, volume 1, 17 janvier 2005, pages 75 et 76.
[31] NS, volume 1, 17 janvier 2005, page 77.
[32] NS, volume 4, 15 février 2005, pages 26 et 27, pièce GI-23, document 1, page 4.

- en étant membre du groupe Enbridge, Gazifère n'a pas besoin de s'offrir par ses propres moyens tous les services requis;
- il y a plusieurs économies d'échelle reliées au fait d'être membre du groupe Enbridge[33].

POSITION DES INTERVENANTS

OC-ACEF de l'Outaouais conclut que la Régie ne devrait pas accepter les charges corporatives de 351 800 $ qu'Enbridge demande à Gazifère pour les motifs suivants :

- le fait que les bénéfices résultant des services dispensés ne sont pas imputés adéquatement;
- le fait que selon une opinion indépendante, la méthode d'allocation des charges corporatives reliée aux services d'Enbridge comporte des failles et ne produit pas une allocation équitable en fonction des principes de causalité des coûts;
- la méthode d'allocation des coûts d'Enbridge n'a pas été approuvée par la Commission de l'énergie de l'Ontario (CEO) dans le cas d'EGD[34].

OC-ACEF de l'Outaouais considère que l'allocation des charges d'administration facturées par Enbridge donne des résultats trop élevés. Il suggère de tenir compte de cette conclusion dans l'établissement d'un montant raisonnable des charges. L'intervenant note que la méthode d'allocation des coûts utilisée remonte à décembre 2003. Cette méthode est identique à la méthode appliquée à EGD et qui fut remise en question par la CEO.

OC-ACEF de l'Outaouais soumet que, dans une procédure récente, la CEO concluait que la méthode d'allocation n'était pas raisonnable. La CEO a donc rejeté la méthodologie utilisée par Enbridge[35]. Elle a demandé qu'une étude indépendante sur la méthode d'allocation soit produite et cette étude a été commandée à Deloitte. Cette dernière a calculé qu'une réduction d'environ un tiers dans l'allocation des coûts corporatifs pour l'année 2005 produirait une charge plus adéquate pour EGD[36]. Les recommandations du rapport ont été mises en application dans une entente négociée entre EGD et ses intervenants et finalement, l'entente a été entérinée par la CEO.

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[33] NS, volume 4, 15 février 2005, page 28.
[34] Pièce OC-ACEF-1, pages 22 et 23.
[35] Dossier RP-2003-023.
[36] NS, volume 2, 18 janvier 2005, page 169, OC-1, pages 15 à 18.

VECC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 6: Are the affiliate charges appropriate?

Reference: Exhibit A1 Tab 9 Schedule 1

a) Please provide 2011A, 2012F and 2013F Volumes and Deliveries on Vector and Alliance and TCPL.

b) Confirm that for deliveries to Parkway Union C1/M1 tolls are incurred.

c) Provide a schedule that shows 2013 tolls, Volumes and Costs for each service purchased on Vector, Alliance and TCPL.

d) Normalize to a Volume/distance amount for each

e) Show the forecast 2013 average unit costs and total transportation costs for deliveries at Parkway for each path.

f) For the System Gas Portfolio compare and comment on the costs of deliveries to the Central Region by alternative paths. Compare/contrast relative Competitiveness of Vector/Alliance Tolls relative to TCPL and including Union C1/M12.

RESPONSE

a) The volumes listed below represent the purchases made in western Canada and moved through Enbridge's contract with TCPL; volumes purchased in western Canada and moved through Alliance (which are then moved on Vector to Dawn); and volumes purchased in Chicago and moved on Vector to Dawn.

Witnesses: J. Sarnovsky
D. Small

	Actual 2011 10^3m^3	Estimate 2012 10^3m^3	Budget 2013 10^3m^3
TCPL	1,748,963.9	2,482,442.8	2,810,011.1
Alliance	963,464.1	957,382.1	957,382.1
Vector	1,800,727.4	1,837,120.7	1,837,120.7

b) Volumes delivered to Parkway-Cons i.e., from TCPL do not need any further transport. Volumes delivered to Parkway-Union would require transport on TCPL STS to get the gas to the franchise area (CDA or EDA).

c) The tolls underpinning the 2013 application can be found at Exhibit D1, Tab 2, Schedule 2, page 1 and the forecast volumes and associated dollars can be found at Exhibit D3, Tab 3, Schedule 1, page 1.

d) Enbridge does not understand the question and cannot offer a response.

e) and f)

The following table shows the relative cost of each requested transportation path.

Relative Competitiveness of Vector/Alliance Tolls relative to TCPL and including Union C1/M12

Pipeline/Path (A)	Point of Supply (B)	Supply Cost $CDN/GJ (C)	Unitized Demand Charge $CDN/GJ (D)	Commodity Charge $CDN/GJ (E)	Fuel Charge $CDN/GJ (F)	100% LFT With Fuel $CDN/GJ (G) = D+E+F	**Landed Cost $CDN/GJ (H) = D+G**	Point of Delivery (I)
Union/Dawn-Parkway-CDA (M12 - STS)	Dawn	3.7784	0.1325	0.0002	0.0336	0.1663	**3.94**	Enbridge CDA
TCPL	Dawn	3.7784	0.2464	0.0136	0.0044	0.2644	**4.04**	Enbridge CDA
Alliance/Vector/Dawn	CREC	3.1675	1.8595	-0.2063	0.2119	1.8652	**5.03**	Enbridge CDA
TCPL	Empress	2.9962	2.0991	0.1438	0.0814	2.3243	**5.32**	Enbridge CDA

Generally speaking, the shorter the distance of the transportation path, the lower the cost. However, cost is just one factor that is considered when putting together a gas supply portfolio. Other factors taken into account include diversity, in terms of supply source and transportation path, operational flexibility of the transportation, and reliability of service.

Witnesses: J. Sarnovsky
D. Small

APPRO INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 7: Are the proposed depreciation rate changes appropriate?

Reference: Exhibit D2, Tab 2, Schedule 1 (Depreciation Study)

Gannett Fleming makes certain recommendations regarding depreciation rates proposed for 2013.

On page 33 of 158 in discussing the rationale to increase the average service life estimate of distribution services, Gannett Fleming proposes to change from the current Iowa 35-S2.5 and use the Iowa-L-1.5 curve and indicates that it is consistent with the historic trends and the views of staff. The Gannett Fleming report also indicates:

> *"The expectation of the Operational staff is that, because the system is now largely comprised of plastic pipe, the future life of the plant will not be impacted by future programs related to early generation plastic pipe, and the historic indications provide for a meaningful analysis of the future life expectations."*

a) Please confirm that replacement programs related to use of early generation plastic pipe and replacement of certain fittings or couplings have resulted in relatively early replacement of distribution services. If not confirmed, please explain.

b) If Enbridge is now using better plastic products, please explain why historic indications provide a meaningful analysis for future life expectations.

c) Gannett Fleming recommends that the average service life for services be extended from 35-S2.5 to 40-L1.5. Even with the new 40 year average service life this is on average 10 years shorter than the other Canadian comparator companies. Please explain why the average service life should not be more similar to its comparators.

d) Gannett Fleming recommends an increase to the average service life for distribution mains – plastic from 50-S2 to 55-R3. The comparator companies provided have an average service life of 65 years. Please explain why an average service life closer to its comparators should not be used.

Witnesses: L. Au
S. Kancharla
D. Kelly

e) For distribution services and distribution mains- plastic, Enbridge has been using a much lower average service life than its comparators. The average service life will continue to be less than its comparators. Will 'over depreciating' assets not require a subsequent adjustment in the future to correct for this higher rate?

RESPONSE

a) The plastic pipe and the processes related to installation of plastic distribution services have evolved since the late 1960's when they first started to be used in the Enbridge Gas Distribution system. The pipe manufacturing process has improved and has resulted in improved and more consistent quality of plastic pipe since the early 1980's. Additionally, the fittings used in the connections from the distribution mains to the service lines and the fusion process used in the jointing of the pipe have also improved. Given the improvements in the pipe, fitting and installation processes, the Company has historically experienced some relatively earlier replacement on the distribution service lines than will be expected in the future related to these specific causes.

b) Distribution service lines are retired due to a number of specific causes including the following:

- Physical age and condition of the pipe;
- Capacity of the service line;
- Re-routing of the service line to meet changes to the customer use of the land;
- Re-routing of the service line to accommodate outside pressure regulation and metering equipment (move from inside); and
- Retirement of the service due to discontinuation of service to the customer.

As indicated in the above list, age and condition of the line is only one cause of potential retirement activity. The remaining causes of retirement activity are not dependent upon the pipe material used in the distribution service line. Therefore, the historic retirement activity provides some meaningful information that requires consideration in the development of the average service life estimate.

c) As indicated in response to part b) of this interrogatory, age and condition is only one of the causes of retirement that is considered in the development of average service life. The historic retirement patterns should not be ignored in the average service life considerations as they include a variety of causes of retirement related to

all service line installations for approximately 100 years. The causes of retirement and average service life estimates will vary from utility to utility based on service territory, mix of pipe types within the system, mix of customer types (i.e., industrial, commercial, and residential), and regulatory policy. As such, peer analysis is only one of the many considerations that should be used in the development of average service life estimates.

The change in the average service life estimate in this depreciation study from 35 to 40 years represents a 14% increase in the life estimate, while still maintaining a very good fit to the historic retirement patterns. In the recommendation of the 40 year average service life, Gannett Fleming specifically considered the magnitude of change that resulted from the fit to the historic mortality indications, the estimates used by peers, and the changing mix of the assets in service. Gannett Fleming also considers that a concept of moderation should be followed in circumstances where large changes in the average service life indications are apparent, and that the life estimates may need to be changed over the course of multiple studies rather than large changes made at once. In this manner, the trend to changing life indications can be confirmed over multiple studies and placing too much emphasis on shorter term trends will be eliminated. Based on these considerations, Gannett Fleming feels that a 14% increase in the life estimate is significant and reasonable at this time.

d) As indicated in response to part b) of this question, age and condition is only one of the causes of retirement that is considered in the development of average service life. The causes of retirement and average service life estimates will vary from utility to utility based on capacity constraints, road allowance re-locations, required relocations due to highway and road crossing, mix of customer types (i.e., industrial, commercial and residential), and regulatory policy. As such, peer analysis is only one of the many considerations that should be used in the development of average service life estimates.

The change in the average service life estimate in this depreciation study from 50 to 55 years represents a 10% increase in the life estimate, and brings the life estimate to within five years of the estimate used for plastic distribution mains in the Union Gas system (as indicated in the Gannett Fleming depreciation study, page II-27). In making the recommendation of the 55 year average service life, Gannett Fleming specifically considered the magnitude of change that resulted from the fit to the historic mortality indications, the estimates used by peers, and the changing mix of the assets in service. Gannett Fleming also considers that a concept of moderation should be followed in circumstances where large changes in the average service life indications are apparent, and that the life estimates may need to be changed over

the course of multiple studies rather than large changes made at once. In this manner, the trend to changing life indications can be confirmed over multiple studies and placing too much emphasis on shorter term trends will be eliminated. Based on these considerations, Gannett Fleming feels that a 10% increase in the life estimate is significant and reasonable at this time.

Witnesses: L. Au
S. Kancharla
D. Kelly

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 7: Are the proposed depreciation rate changes appropriate?

Ref: D1/T5/S1

Please provide the Terms of Reference for the Gannet Fleming Study. Was the study subject to an RFP? If not, why not?

RESPONSE

a) The Terms of Reference for the Gannet Fleming Study are noted on the following page.

b) No, the study was not subject to an RFP.

c) An RFP was not undertaken due to the relatively low cost (estimated cost was $40k) and due to the established professional services provided by Gannet Fleming in the past. They have prepared every deprecation study since the 2001 study which was reviewed in the RP-2002-0133 Rate Proceeding dealing with the 2003 Test Year. Current depreciation rates have been in place since October 1, 2002, the start of fiscal 2003, and are based on the 2001 Depreciation Study by Gannet Fleming as approved by the Board in the RP-2002-0133 Settlement Proposal (RP-2002-0133, Exhibit N1, Tab 1, Schedule 1, p. 31).

Witnesses: L. Au
S. Chhelavda
D. Kelly

DEPRECIATION STUDY –REGULATED ASSETS

Scope of Services:

The Consultant will undertake an updating to a prior depreciation study using U.S. GAAP principles based upon the regulated assets of Enbridge plant in service as at year end 2010 (December 31, 2010). The following scope of services are a part of this assignment:

- Completion of a service life study which will include a review of plant accounting data and plant balances at the 2010 fiscal year end (December 31, 2010), a field review of facilities and the estimation of survivor curves;
- Completion of a study for the estimation of the cost of retirement;
- Determination of the adequacy of the current accumulated depreciation accounts to reflect the consumption of the consumed service value of the gas storage assets, and cost of removal requirements;
- Calculation of the annual depreciation accrual rates related to the recovery of original cost of investment and for the future removal and retirement of plant in service;
- Calculation of the decommissioning liability, if applicable, and proposed accretion rates.
- Calculation of the portion of "future removal and retirement of plant" accrual that is included in the accumulated depreciation.

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 8: Is the municipal taxes expense appropriate?

Ref: D1/T6/S1/p2

At para 5 and 6, the evidence states that there will be growth in taxes due to "new, reinforcement, and replacement mains and new service connections."

Please specify what these mains and service connections are, the related costs and variance over historical municipal taxes, and whether or not the work described is for expansions or initiatives which are projected or finalized as of the current period.

RESPONSE

In developing the budget for municipal tax purposes, the Company has incorporated an average tax increase experienced over the past 12 years in the amount of $655,000 for all additional growth to the distribution system for new, reinforcement and replacement mains, along with new service connections for the 2012 and 2013 tax years. Forecasts are not specifically related to capital costs of individual projects, new expansions or replacement mains within the distribution system. Service connections pertain to new customers being added to the system. Also, please refer to the response given to Energy Probe Interrogatory, at Exhibit I, Issue D8, Schedule 7.1.

Witness: B. Remington

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 8: Is the municipal taxes expense appropriate?

Ref: Exhibit D1, Tab 6, Schedule 1

a) Please confirm that the 2011 figure of $37.0 million is an actual figure for 2011. If this cannot be confirmed, please provide the actual figure for 2011.

b) Please expand the table to show actual municipal taxes for 2007 through 2011.

c) Please provide the total assessment value used for municipal tax purposes for 2007 through 2011, along with the forecast for 2012 and 2013.

d) Please provide the weighted average property tax rates that were recorded in 2007 through 2011 and the forecasts for 2012 and 2013 respectively.

RESPONSE

a) The $37.0 million figure included in the pre-filed evidence was a forecast 2011 utility municipal tax amount. The actual 2011 utility municipal tax figure is $37.4 million.

b) The following table has been expanded to include 2007 through 2011 actual utility municipal tax amounts.

CONTINUITY OF UTILITY MUNICIPAL TAX EXPENSE

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
$ Millions	2013 Budget	2012 Estimate	2011 Actual	2010 Actual	2009 Actual	2008 Actual	2007 Actual	2007 Board Approved
Utility Municipal Taxes	$40.1	$38.8	$37.4	$37.4	$35.7	$36.5	$35.9	$36.1

Witness: B. Remington

c) Total assessment value base used for municipal tax purposes:
2007 taxation year = 1,188,715,200 (base year as at January 1, 2005)
2008 taxation year = 1,202,449,900 (base year as at January 1, 2005)
2009 taxation year = 1,254,302,729 (base year as at January 1, 2008 phased-in)
2010 taxation year = 1,306,679,475 (base year as at January 1, 2008 phased-in)
2011 taxation year = 1,349,949,926 (base year as at January 1, 2008 phased-in)
2012 taxation year = 1,419,353,500 (base year as at January 1, 2008 phased-in)
2013 taxation year = 1,492,325,000 (estimated - base year as at January 1, 2012 phased-in over previous base year as at January 1, 2008 with the 2013 tax year being the first year of a four-year cycle)

Please be advised that in 2008, the Government of Ontario introduced a phase-in program where the increases in assessed value between the January 1, 2005 and January 1, 2008 base years are phased in over four years (2009-2012) with the 2012 taxation year being the fourth year of the four-year cycle. As well, please note that the pipeline assessments for mains and service connections, which account for over 92% of EGD's total property taxes, are assessed by regulated rates made by the Minister of Finance. Also, the current value assessments of the numerous owned fee simple properties are based on income/economic and cost approaches to value.

d) The weighted property tax rate system-wide are:
2007 tax year = 3.0200673%
2008 tax year = 3.0354695%
2009 tax year = 2.8462028%
2010 tax year = 2.8622168%
2011 tax year = 2.7704731%
2012 tax year = 2.7336389% (estimated)
2013 tax year = 2.6870822% (estimated)

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 8: Is the municipal taxes expense appropriate?

Reference: Exhibit D1 Tab 6 Schedule 1

a) Please update the Municipal Tax amount for 2011.

b) Please provide continuity for municipal taxes for 2007 through 2013F.

RESPONSE

a) The $37.0 million figure included in the pre-filed evidence was a forecast 2011 utility municipal tax amount. The actual 2011 utility municipal tax figure is $37.4 million.

b) The following table has been expanded to include 2007 through 2011 actual utility municipal tax amounts.

CONTINUITY OF UTILITY MUNICIPAL TAX EXPENSE

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
$ Millions	2013 Budget	2012 Estimate	2011 Actual	2010 Actual	2009 Actual	2008 Actual	2007 Actual	2007 Board Approved
Utility Municipal Taxes	$40.1	$38.8	$37.4	$37.4	$35.7	$36.5	$35.9	$36.1

Witness: B. Remington

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 9: Is the demand side management budget appropriate?

Ref(1): ExD1/Tab7/Sch 1/p.1
Ref(2): EB-2011-0295 (2012-2014 DSM Plan)
B1/T1/Sch. 1/p.5

a) Please confirm that the Board has approved a $30.91 million spending envelope for DSM at Enbridge in 2013.

RESPONSE

As outlined in Exhibit D1, Tab 7, Schedule 1, page 2, upon applying the DSM Plan Section 8 Guidelines, the 2013 Board Approved DSM costs are determined to be $31.4 million.

Witnesses: K. Culbert
A. Mandyan

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 10: Is the income tax expense forecast appropriate?

Ref: Ex. D5/Tab 1/Sch 1

Enbridge filed the calculation of 2011 utility income tax at Ex. D5/Tab 1/Sch 1.

a) Please provide the signed tax return for 2011 submitted to the Canada Revenue Agency ("CRA") and any tax assessments and reassessments, if applicable, for the years 2009 and 2010.

b) Please provide a schedule that ties the 2011 UCC schedule at Ex. D5/Tab 1/Sch 1/page 7 to Schedule 8 of the signed 2011 tax return. Please reconcile and provide explanations for differences between the 2011 UCC schedule at Ex. D5/Tab 1/Sch 1/page 7 and Schedule 8 of the signed 2011 tax return.

RESPONSE

a & b) Enbridge's corporate tax return contains information about unregulated business activities that is not releveant to regulated utility operations. Further, the corporate tax return presents information with respect to corporate activities on a consolidated basis, such that there is no segregated presentation of regulated utility information that would or could be relevant in a rate-making proceeding for the regulated utility. For these reasons, Enbridge respectfully declines to produce the corporate tax return.

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 10: Is the income tax expense forecast appropriate?

Ref(1) : Ex. D3/Tab 1/Schedule 1
Ref(2) : Ex. D4/Tab 1/Sch 1
Ref(3) : Ex. D5/Tab 1/Sch1

a) Please confirm that the capital assets shown on the CCA calculation schedules provided by Enbridge are 100% related to Enbridge's regulated business, except for the elimination of "Non-utility and shared asset eliminations." Please provide an explanation and the supporting documents if otherwise.
b) If the capital assets shown on the CCA calculation schedules provided by Enbridge are not 100% related to Enbridge's regulated business, please provide the breakdown between the regulated business and unregulated business for Enbridge's book values and tax values of the assets.

RESPONSE

a) Confirmed.

b) See response to part a).

Witnesses: K. Culbert
R. Small

BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 10: Is the income tax expense forecast appropriate?

Ref: Ex. M1/ Tab 1/Sch 4

Please provide a description of the methodology used by Enbridge to calculate its utility income taxes for the 2013 Test Year in Ex. M1/ Tab 1/ Sch 4

Please disclose any significant changes that Enbridge has incorporated into its 2013 utility income tax calculation compared to its last rebasing proceeding, EB-2006-0034. Please compare Enbridge's proposed methodology in EB-2011-0354 to the methodology that was agreed to by parties in EB-2006-0034. The changes should include but not limited to the:

i. impact from the transition to USGAAP;
ii. CCA class changes for Enbridge's existing capital assets;
iii. CCA rate changes for Enbridge's existing capital assets; and
iv. CCA class and rates chosen for the capital assets additions in 2013.

RESPONSE

The calculation of the utility income taxes, excluding CIS/Customer Care amounts which are part of a separate approved agreement, in Exhibit M1, Tab 1, Schedule 4 was arrived at through the following process and methodology.

The determination of utility income taxes commences with the use of financial information contained in the 2013 EGDI Ontario corporate budget.

As shown in Enbridge's originally filed evidence at Exhibit C3, Tab 1, Schedule 1, page 3 Column 1, and Exhibit D3, Tab 1, Schedule 1, page 4 Column 1, corporate budgeted income, and more specifically the elements of corporate revenue and expenses including income taxes, are the starting point for developing utility income and utility income taxes. The budgeted corporate revenues and expenses are then adjusted for

Witnesses: K. Culbert
S. Chhelavda
B. Yuzwa

elements of revenues or costs which are not permitted or properly included in Enbridge's utility income, as explained in those exhibits. Within those adjustments, corporate income taxes are also eliminated as seen in rows 19 and 20 in Exhibit D3, Tab 1, Schedule 1, page 4. As approved in the past, the Company continues to seek approval to recover utility income taxes on a flow through basis exclusive of deferred taxes. Corporate income taxes include the recognition of deferred taxes and therefore are eliminated as indicated earlier and are replaced with utility income taxes calculated and shown at Exhibit D3, Tab 1, Schedule 1, page 3.

The calculation of utility income taxes starts with utility accounting income of $281.5 million as shown at Exhibit D3, Tab 1, Schedule 1, page 3, Line 1, Columns 1 and 2. Utility accounting income is produced as indicated earlier, through the process of making adjustments to convert corporate revenues and expenses to utility revenues of $2,498.8 million shown at Exhibit C3, Tab 1, Schedule 1, page 1, Line 7, Column 3 and utility expenses of $2,217.3 million shown at Exhibit D3, Tab 1, Schedule 1, page 1, Line 8, Column 3, the net of which is the $281.5 million of utility accounting income.

The utility accounting income is then converted to what is recognized as taxable income by the Canada Revenue Agency ("CRA"). For example depreciation recognized for accounting purposes is added back to accounting income and tax depreciation, known as Capital Cost Allowance ("CCA") recognized by the CRA, is deducted from accounting income in the process of determining taxable income. Additionally, any other items which require a different treatment by the CRA within the determination of taxable income than is permitted in determining accounting income, are added back to or deducted from accounting income as shown in Exhibit D3, Tab 1, Schedule 1, page 3, Columns 1 and 2. Again, as an example, certain elements of costs permitted to be capitalized for regulatory and accounting income purposes are deductible immediately for taxable income purposes, shown within the above noted tax exhibit at Line 7, Columns 1 and 2.

In addition to the adjustments required by the CRA in the determination of taxable income, all other adjustments required to adjust for the impacts of Board determined non-utility elements or un-regulated items are also made. An example is the elimination of immediately deductible interest during construction available corporately, which within the regulatory model construct is treated as part of rate base and therefore receives interest deduction impacts within the interest income tax credit calculation as shown at the bottom of Exhibit D3, Tab 1, Schedule 1, page 3. Another example is the adjustment to corporate CCA to remove the impacts of non-utility and un-regulated capital spend and asset values to arrive at utility CCA. Other elements included in the determination of corporate current and deferred taxes, such as the inclusion of year

over year changes in deferral account amounts, are also removed for the purpose of determining utility taxable income as such elements are not properly included in taxable income for the purpose of calculating flow through utility taxes.

After making all of the above noted adjustments, the resulting taxable income was determined to be $280.6 million shown at Exhibit D3, Tab 1, Schedule 1, page 3, Line 13.

As a result of the further changes identified and explained throughout the M1 Exhibit, that taxable income of $280.6 million is adjusted to $269.8 million as shown in Exhibit M1, Tab 1, Schedule 4, page3, Column 3, Lines 15 and 16. The adjusted $269.8 million of taxable income is then multiplied by corporate federal and provincial income tax rates to determine utility taxes of $71.5 million, shown at Line 21, Column 3. The additional tax impacts of taxable dividends treatment and the regulatory model allowed interest expense treatments are accommodated in Lines 22 through 29, producing utility income taxes of $37.3 million shown at Column 3, Line 30.

The changes in CCA classes and rates and the explanation of the impact of the transition to USGAAP are identified below.

There are no significant other changes in the utility income tax calculations within this 2013 application in comparison to Enbridge's last cost of service proceeding.

i) The impact of the transition to USGAAP on the calculation of utility income tax, which has not been accommodated to date, is explained in the response to Board Staff Interrogatory #6 at Exhibit I, Issue D4, Schedule 1.6.

ii & iii) The CCA class and rate changes since 2007, for Enbridge's existing capital assets, have been provided and adjusted where required through each year during Enbridges 2008-2012 IR rate setting mechanisms and or through the derivation of amounts to be included within the Board approved Tax Rate and Rule Change Variance Account. The Company has provided a copy of the most recent "Summary – Sharing of Tax Change Forecast Amounts" table, which was agreed to and approved within EGD's Fiscal 2012 EB-2011-0277 proceeding (See Attachment). Corresponding CCA class and rate changes have also been used in the derivation of actual and forecast results over the same time period.

iv) The CCA classes and rates chosen for the capital assets additions in 2013 are shown in Exhibit D3, Tab 1, Schedule 1, page 7.

Witnesses: K. Culbert
S. Chhelavda
B. Yuzwa

Table 1

Updated Summary - Sharing of Tax Change Forecast Amounts
(2011 Approved Sharing amounts updated for changes resulting from HST impacts)

Line No.		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2008	**2009**	**2010**	**2011**	**2012**	
	Tax Related Amounts Forecast from CCA Rate Changes **($ Millions)**						
1.	Computer Equipment (Class 45) - Opening UCC Balance	1.65	2.56	3.06	3.33	3.48	
2.	New purchases (2007 Board Approved additions)	2.13	2.13	2.13	2.13	2.13	
3.	Capital Cost Allowance (CCA) at 45% -former tax rule CCA rate	1.22	1.63	1.86	1.98	2.05	
4.	Closing Undepreciated Capital Cost (UCC)	2.56	3.06	3.33	3.48	3.57	
5.	Computer Equipment (Class 45/50) - Opening UCC Balance	1.54	2.24	1.14	0.51	1.64	
6.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	2.13	2.13	2.13	2.13	2.13	
7.	**Re-grouping of amounts eligible for Class 52 (included at line 11)**	-	(1.95)	(2.13)	(0.18)	-	
8.	Capital Cost Allowance (CCA) at 55% -2007 Federal Budget tax rule CCA rate	1.43	1.28	0.63	0.82	1.49	
9.	Closing Undepreciated Capital Cost (UCC)	2.24	1.14	0.51	1.64	2.28	
10.	Computer Equipment (**New Class 52**) - Opening UCC Balance	-	-	-	-	-	
11.	New purchases (2007 Board Approved additions) - **with update for new Class 52**	-	1.95	2.13	0.18	-	
12.	Capital Cost Allowance (CCA) at 100% -2007 Federal Budget tax rule CCA rate	-	1.95	2.13	0.18	-	
13.	Closing Undepreciated Capital Cost (UCC)	-	-	-	-	-	
14.	Distribution Assets (Class 1) - Opening UCC Balance	238.66	467.76	687.71	898.86	1101.57	
15.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
16.	Capital Cost Allowance (CCA) at 4% -former tax rule CCA rate	14.42	23.58	32.38	40.83	48.93	
17.	Closing Undepreciated Capital Cost (UCC)	467.76	687.71	898.86	1101.57	1296.16	
18.	Distribution Assets (Class 51) - Opening UCC Balance	236.23	458.28	667.01	863.21	1047.64	
19.	New purchases (2007 Board Approved additions)	243.53	243.53	243.53	243.53	243.53	
20.	Capital Cost Allowance (CCA) at 6% -2007 Federal Budget tax rule CCA rate	21.48	34.80	47.33	59.10	70.16	
21.	Closing Undepreciated Capital Cost (UCC)	458.28	667.01	863.21	1047.64	1221.01	
22.	CCA Difference	7.27	12.82	15.85	17.29	20.67	
23.	Tax Rate (Anticipated Corporate Income Tax Rates during IR term)	33.50%	33.00%	31.00%	28.25%	26.25%	
24.	Tax Impact	2.44	4.23	4.91	4.89	5.43	
25.	Grossed-up Tax Amount (Cumulative Total Forecast)	3.65	6.31	7.12	6.81	7.36	31.26
26.	Incremental Amount	3.65	2.66	0.81	(0.31)	0.55	
27.	**50% of the Amount to Reduce Rates**	**$1.83**	**$1.33**	**$0.40**	**-$0.16**	**$0.28**	
	Tax Related Amounts Forecast from Income Tax Rate Changes						
28.	Taxable Income (2007 Board Approved, Final Rate Order, App.A, S3,P3,L15)	355.6	355.6	355.6	355.6	355.6	
29.	Gross Deficiency (2007 Board Approved, Final Rate Order, App.A, S1,P1,L7)	42.7	42.7	42.7	42.7	42.7	
30.	Interest Expense (2007 Board Approved, Final Rate Order, App.A, S3,P3,L25)	(165.90)	(165.90)	(165.90)	(165.90)	(165.90)	
31.	Board Approved Taxable Income for Income Tax Expense Calculation	232.40	232.40	232.40	232.40	232.40	
32.	2007 Approved Tax Rate (2007 Board Approved, Final Rate Order, App.A, S3,P3,L27)	36.12%	36.12%	36.12%	36.12%	36.12%	
33.	Anticipated Tax Rates During the IR Term	33.50%	33.00%	31.00%	28.25%	26.25%	
34.	Tax Rate Variance	2.62%	3.12%	5.12%	7.87%	9.87%	
35.	Annual Income Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	6.09	7.25	11.90	18.29	22.94	
36.	Grossed-up Tax Savings	9.16	10.82	17.25	25.49	31.11	93.83
37.	Incremental Amount	9.16	1.66	6.43	8.24	5.62	
38.	**50% of the Amount to Reduce Rates**	**$4.58**	**$0.83**	**$3.22**	**$4.12**	**$2.80**	
	Capital Tax Related Amounts Forecast from Capital Tax Rate Changes						
39.	2007 Taxable Capital as Filed (EB-2006-0034, D3,T1,S1,P6,L7)	3,571.0	3,571.0	3,571.0	3,571.0	3,571.0	
40.	2007 Decision and Settlement Agreement Adjustments to Taxable Capital	(118.8)	(118.8)	(118.8)	(118.8)	(118.8)	
41.	2007 Board Approved Taxable Capital	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
42.	2007 Board Approved Capital Tax Rate (EB-2006-0034, D3,T1,S1,P6,L8)	0.285%	0.285%	0.285%	0.285%	0.285%	
43.	Anticipated Capital Tax Rates During the IR Term	0.225%	0.225%	0.075%	0.000%	0.000%	
44.	Capital Tax Rate Variance	0.060%	0.060%	0.210%	0.285%	0.285%	
45.	Annual Capital Tax Savings vs. 2007 Approved Taxes (Cumulative Total Forecast)	2.07	2.07	7.25	9.84	9.84	31.07
46.	Incremental Amount	2.07	0.00	5.18	2.59	0.00	
47.	**50% of the Amount to Reduce Rates**	**$1.03**	**$0.00**	**$2.58**	**$1.30**	**$0.00**	
	Capital Tax Related Amounts Forecast from Taxable Capital Changes						
48.	2007 Board Approved Taxable Capital (Row 41 above)	3,452.2	3,452.2	3,452.2	3,452.2	3,452.2	
49.	Revised 2007 Board Approved Taxable Capital Resutling From Rule Changes	3,452.2	4,098.1	4,098.1	4,098.1	4,098.1	
50.	Incremental Taxable Capital	0.0	(645.9)	(645.9)	(645.9)	(645.9)	
51.	Anticipated Capital Tax Rates During the IR Term (Row 43 above)	0.225%	0.225%	0.075%	0.000%	0.000%	
52.	Annual Capital Tax Increase vs. 2007 Approved Taxes (Cumulative Total Forecast)	0.00	(1.45)	(0.48)	0.00	0.00	(1.93)
53.	Incremental Amount	0.00	(1.45)	0.97	0.48	0.00	
54.	**50% of the Amount to Reduce Rates**	**$0.00**	**($0.73)**	**$0.49**	**$0.24**	**$0.00**	
	Revenue Requirement Amounts Forecast from HST Change Impacts						
55.	Net cumulative revenue requirement benefit (Ex.B, T1, S.5, pg.1, line 11)	-	-	0.6	1.7	2.2	
56.	Income tax rates	-	-	31.00%	28.25%	26.25%	
57.	Gross cumulative revenue requirement benefit (Ex.B, T1, S.5, pg.1, line 12)	-	-	0.9	2.4	3.0	6.30
58.	Incremental Amount	-	-	0.9	1.5	0.6	
59.	**50% of the Amount to Reduce Rates**	-	-	**$0.45**	**$0.75**	**$0.30**	
60.	**Cumulative Total Forecast Tax Related Amount (lines 25+36+45+52+57)**	**14.88**	**17.75**	**32.04**	**44.54**	**51.31**	160.53
61.	**Total Incremental Ratepayer Amounts into rates (lines 27+38+47+54+59)**	**$7.44**	**$1.43**	**$7.14**	**$6.25**	**$3.38**	
62.	**Updated of Annual Ratepayer & Company Shareholder Tax Savings (50% of row 60)**	**$7.44**	**$8.87**	**$16.01**	**$22.26**	**$25.64**	$80.22
63.	**2011, EB-2010-0146 Approved / Updated Agreement Annual Ratepayer Tax Savings**	***$7.44***	***$8.87***	***$15.56***	***$21.06***	***$24.14***	*$77.07*
64.	Incremental 2010 TRRCVA credit from the HST change ($16.01M - $15.56M) (col.3, line 62 - 63)			0.45			
65.	2011 TRRCVA credit from the HST change ($22.26M - $21.06M) (col.4, line 62 - col.4, line 63)				$1.20		
66.	Ratepayer share of 2012 incremental tax amounts ($25.64M - $21.06M) (col.5, line 62 - col.4, line 63)					$4.58	
67.	Amounts previously Approved in EB-2010-0146 to be debited into the 2010 TRRCVA			(0.97)			
68.	Net updated 2010 TRRCVA debit amount recoverable from ratepayers ((0.97) - 0.45) (col.3, line 64 - col.3, line 67)			(0.52)			

BOARD STAFF INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 10: Is the income tax expense forecast appropriate?

Ref(1): Ex. B1 / Tab 2/ Sch 1/ Appendix 1 (updated June 1, 2012)
Ref(2): Ex. D3/ Tab 1/Sch 1
Ref(3): Ex. D4/ Tab 1/Sch 1
Ref(4): Ex. D5/ Tab 1/Sch 1

Capital Expenditures on UCC Schedule and Rate Base Schedule

a) Please reconcile the capital expenditures on Ex. B1 / Tab 2/ Sch 1/ Appendix 1 (updated June 1, 2012) of:

- $399.2 for 2011
- $404.5 million for 2012
- $483.9 million for 2013

to the capital expenditures reported on the respective UCC schedules of:

- $317.7 million for 2011 (Ex. D5/ Tab 1/Sch 1)
- $419.5 million for 2012 (Ex. D4/ Tab 1/Sch 1), and
- $375.4 million for 2013 (Ex. D3/ Tab 1/Sch 1).

Please provide explanations for differences.

b) Please clarify which capital expenditures are the correct numbers. Please explain.

c) Please update EGD's evidence where appropriate (e.g. rate base section or tax provision section of application).

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei

RESPONSE

a) The amounts contained in Updated Exhibit B1, Tab 2, Schedule 1, Appendix 1 are utility capital expenditures forecast in the calendar year, inclusive of interest during construction and capitalized overheads. The amounts do not reflect calendar year additions to the in-service property, plant, and equipment component of rate base, as there are work in progress fluctuations to be considered. The amounts contained in Exhibits D5, D4, and D3, Tab 1, Schedule 1 reflect annual additions to utility capital cost allowance (CCA) pools for tax purposes. By contrast, additions to CCA pools do reflect asset amounts which have been put into service during the calendar year. There are however differences between CCA pool additions and rate base property, plant, and equipment additions. CCA pool additions do not include items which are expensed immediately for tax purposes, such as capitalized interest during construction or a portion of capitalized overheads. In addition, CCA pool additions do not include amounts which are amortized as part of Canadian Development Expenditures or as part of Canadian Oil and Gas Property Expenditures. Finally, CCA pool additions do not include non-depreciable asset additions, such as land.

b) The following table is a reconciliation of capital expenditures shown in Updated Exhibit B1/T2/S1/App.1 to the UCC pool additions which should have been included within the UCC schedules shown in Exhibits D3/T1/S1/p.7, D4/T1/S1.p.6, and D5/T1/S1/p.7. Please note, the 2013 capital expenditures shown in the attached reconciliation, have been updated to reflect the $2 million capital increase related to the updated forecast of pension expense included within Impact Statement #1, (Ref. Ex.M1.T1.S1.p.2.Para.5).

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei

Reconcilation of Capital Expenditures to Capital Cost Allowance Pool Additions

	2011 Actual ($Millions)	2012 Bridge Year ($Millions)	Updated 2013 Test Year ($Millions)
Capital expenditures	403.6	404.5	485.9
Work in progress fluctuation	(61.8)	42.2	(83.5)
Capitalized overheads expensed for tax purposes	(19.8)	(21.0)	(27.2)
Capitalized interest expensed for tax purposes	(5.2)	(3.8)	(5.0)
Land expenditures	(7.4)	(4.3)	(2.8)
Storage expenditures excluded from CCA pool adds (COGPE & CDE)	(3.1)	(1.4)	(1.1)
Reconciling Adjustment	(0.1)	0.2	(0.3)
Capital cost allowance pool additions	306.2	416.4	366.0

Note: The 2011 Actual reconciliation contains forecast values utilized in the year end tax provision, which were required due to year end information and timing restrictions.

c) In preparing this reconciliation, EGD discovered that the UCC pool additions did not properly account for and eliminate some amounts which were able to be, and were properly recognized as immediate tax deductibles. The result of the error is that the 2013 opening UCC balance was overstated by $3.1 million and the pool additions were overstated by $9.4 million. The amounts allowed as immediate tax deductibles, are included within “Items capitalized for regulatory purposes” shown at line 8 of the Income Tax Expense calculation shown in Exhibit M1/T1/S4/p.3. The impact of correcting the error will result in the CCA deduction of $237.2 million, as shown at line 6, column 3 in Exhibit M1/T1/S4/p.3 being reduced by $2.4 million to $234.8 million. The result is that utility taxable income is currently understated by approximately $2.4 million, with the deficiency being understated by approximately $0.9 million. EGD has attached corrected UCC/CCA schedules below, the impact of which will be incorporated into Impact Statement #2, to be filed in early August.

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2013 TEST YEAR

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2013	UCC Carry Forward
1	1,862,541,898	-	-	-	4.00%	(74,501,676)	1,788,040,222
51	1,274,096,176	298,284,252	-	149,142,126	6.00%	(85,394,298)	1,486,986,130
2	121,658,411	-	(159,751)	(79,876)	6.00%	(7,294,712)	114,203,948
6	13,649	-	-	-	10.00%	(1,365)	12,284
8	10,162,417	5,031,973	-	2,515,987	20.00%	(2,535,681)	12,658,709
10	20,204,915	4,079,852	(140,119)	1,969,867	30.00%	(6,652,435)	17,492,214
12	22,081,028	32,760,192	(20,407)	16,369,893	100.00%	(38,450,920)	16,369,893
12	-	-	-	-	-	-	-
17	32,384	-	-	-	8.00%	(2,591)	29,793
38	4,856,278	1,581,011	(49,566)	765,723	30.00%	(1,686,600)	4,701,123
41	42,257,005	12,535,000	-	6,267,500	25.00%	(12,131,126)	42,660,878
13	5,709,431	3,534,000	-	1,767,000	-	(249,000)	8,994,431
3	236,719	-	-	-	5.00%	(11,836)	224,883
45	489,747	-	-	-	45.00%	(220,386)	269,361
50	6,618,608	8,171,400	-	4,085,700	55.00%	(5,887,370)	8,902,639
52	-	-	-	-	100.00%	-	-
Total	3,370,958,665	365,977,680	(369,843)	182,803,919		(235,019,995)	3,501,546,507

Non-utility and shared asset eliminations	205,387
Utility CCA	(234,814,608)

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2012 BRIDGE YEAR

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2012	UCC Carry Forward
1	1,940,147,810	-	-	-	4.00%	(77,605,912)	1,862,541,898
51	998,202,097	346,171,345	-	173,085,673	6.00%	(70,277,266)	1,274,096,176
2	129,588,691	-	(159,751)	(79,876)	6.00%	(7,770,529)	121,658,411
6	15,166	-	-	-	10.00%	(1,517)	13,649
8	11,630,425	953,419	-	476,710	20.00%	(2,421,427)	10,162,417
10	21,233,094	6,422,925	(138,514)	3,142,206	30.00%	(7,312,590)	20,204,915
12	13,952,729	44,182,055	(20,000)	22,081,028	100.00%	(36,033,756)	22,081,028
12	30,043,165	-	-	-	100.00%	(30,043,165)	-
17	35,200	-	-	-	8.00%	(2,816)	32,384
38	6,119,048	722,811	(48,759)	337,026	30.00%	(1,936,822)	4,856,278
41	37,214,006	16,396,000	-	8,198,000	25.00%	(11,353,002)	42,257,005
13	5,717,431	241,000	-	120,500	-	(249,000)	5,709,431
3	249,178	-	-	-	5.00%	(12,459)	236,719
45	890,449	-	-	-	45.00%	(400,702)	489,747
50	12,646,065	1,279,833	-	639,917	55.00%	(7,307,290)	6,618,608
52	-	-	-	-	100.00%	-	-
Total	3,207,684,553	416,369,388	(367,024)	208,001,182		(252,728,252)	3,370,958,665

Non-utility and shared asset eliminations	209,786
Utility CCA	(252,518,466)

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei

SUMMARY OF UTILITY CAPITAL COST ALLOWANCE
2011 HISTORICAL YEAR

Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
Class No.	UCC AT Beginning of year	Cost of Additions	Lessor of Costs or Proceeds	Less 50 % of net [Cols 3 - 4]	Rate %	CCA F2011	UCC Carry Forward
1	2,020,987,302	-	-	-	4.00%	(80,839,492)	1,940,147,810
51	825,925,327	228,693,082	-	114,346,541	6.00%	(56,416,312)	998,202,097
2	138,025,159	-	(159,751)	(79,876)	6.00%	(8,276,717)	129,588,691
6	16,851	-	-	-	10.00%	(1,685)	15,166
8	8,880,021	5,029,342	-	2,514,671	20.00%	(2,278,938)	11,630,425
10	23,260,699	5,955,130	(130,889)	2,912,121	30.00%	(7,851,846)	21,233,094
12	13,641,256	27,925,457	(20,000)	13,952,729	100.00%	(27,593,985)	13,952,729
12	60,086,330	-	-	-	50.00%	(30,043,165)	30,043,165
17	38,261	-	-	-	8.00%	(3,061)	35,200
38	5,484,786	2,728,011	(46,014)	1,340,999	30.00%	(2,047,735)	6,119,048
41	30,715,175	16,203,000	-	8,101,500	25.00%	(9,704,169)	37,214,006
13	1,306,431	4,660,000	-	2,330,000	-	(249,000)	5,717,431
3	262,293	-	-	-	5.00%	(13,115)	249,178
45	1,618,999	-	-	-	45.00%	(728,550)	890,449
50	3,882,533	15,033,000	-	7,516,500	55.00%	(6,269,468)	12,646,065
52	-	-	-	-	100.00%	-	-
Total	3,134,131,423	306,227,022	(356,654)	152,935,184		(232,317,238)	3,207,684,553

Non-utility and shared asset eliminations	385,683
Utility CCA	(231,931,555)

Witnesses: L. Au
K. Culbert
S. Kancharla
D. Kelly
R. Lei

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p1/para1
The Open Bill Access Settlement Agreement in EB-2009-0043 expires at December 31, 2012. The Settlement Agreement requires that Enbridge make an application to the Board in order to continue Open Bill Services.

a) Is Enbridge making its application through this evidence to continue providing Open Bill Service, or does Enbridge intend to file a separate application for this purpose?

b) Was notice of Enbridge's 2013 rates application been provided:

i) to all past Open Bill customers,
ii) to all current Open Bill customers; and
iii) in a place and manner that reasonably foreseeable future customers are aware of changes to rates for Open Bill service

If the answer to any of the above questions is "no", please indicate why Enbridge believes that appropriate notice has been given to all parties that may be affected by this change, and why this issue is better addressed in the current proceeding, rather than by way of an application (and possible settlement) that considers and provides adequate notice to the affected parties.

c) If Enbridge intends to file a standalone application subsequent to this proceeding, please indicate what decision Enbridge expects the Board to arrive at in this proceeding. For how long does Enbridge intend for its requested rate change to remain in effect?

Witnesses: K. Lakatos-Hayward
S. McGill

RESPONSE

a) It is the Company's intent to make its application for the continued provision of Open Bill Service to at least the end of 2013 through this application and associated evidence. Enbridge does not anticipate filing a separate application for this purpose.

b) In addition to the normal notices issued by the Company associated with any rate application made to the Ontario Energy Board, the Company has issued a description of the changes to the Open Bill Services Agreement outlined in this application to all current Open Bill clients. As of this time, the Company has not issued such communication to past Open Bill clients or potential future Open Bill clients.

c) Enbridge does not intend to file a standalone application pertaining to Open Bill Services subsequent to this proceeding. Through this application Enbridge intends the revised Open Bill Service fees to remain in effect until the end of 2013. The Company intends to file an update with the Board concerning this program for 2014 in next rate application.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/Appendix1/page4

At the reference above the Board stated that, "The Settlement Proposal before the Board is the result of a lengthy and involved negotiation among the members of the consultative group, and in particular the core members of the group. The Board's own process confirmed that there is no opposition to the Settlement Proposal." (emphasis added)

What in this application confirms for the Board that there is no opposition to Enbridge's proposal to change rates for Open Bill Service, effective January 1, 2013, and that provides assurance to the Board that its new OBA proposal is appropriate?

RESPONSE

There is nothing in this application to confirm that there is no opposition to Enbridge's proposal to change rates for Open Bill Service, effective January 1, 2013. It is the Company's view that the changes to the program presented in its evidence to this proceeding are appropriate. Further, any current or potential Open Bill Service clients that do not find the Company's Open Bill Service offering as presented in this application acceptable are free to carry out the billing and collection of charges pertaining to products or services they provide independent of Enbridge. Enbridge strongly believes that the changes to the program are required to protect the Company's corporate reputation and maintain customer satisfaction and rectify a number of problems that have been experienced in the operation of the program.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p1/para1
The Company states that, "Enbridge wishes to continue to provide Open Bill Service under generally the same terms as set by the Settlement Agreement, with modest increases to the fees and charges paid by billing services clients for 2013." (emphasis added)

With reference to the term "generally", and based on the understanding that there may be certain changes to fees and charges paid under the Enbridge proposal, are there any other terms and conditions which Enbridge proposes to change versus the terms and conditions set out in the 2009 OBA Settlement Agreement?

RESPONSE

At the time the Company filed its original evidence in this proceeding proposed changes to the Open Bill Service were limited to an update of the program's unit costs and open bill service fees. Subsequent to the filing of this evidence the Company became increasingly aware of, and concerned with, questionable sales and contracting practices being perpetrated by some open bill service clients. Based on this experience the Company introduced a number of changes to the Open Bill Services Agreement that will be offered to most current and all prospective Open Bill clients effective January 1, 2013. These contract revisions are detailed in the Company's updated evidence filed with the Board on June 8, 2012.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref(1): Ex D1/T9/S1/p4/para10
Ref(2): Ex D1/T9/S1/p14/Table 4

Enbridge states that one of the Open Bill provisions was that, "Enbridge may change cost per bill annually at rate [sic] of half of the Ontario Consumer Price Index, but in any event the increase will be no greater than 2% per year." (emphasis added)

Enbridge provides Billing Services and Unit Costs & Fees at Table 4.

a) How did Enbridge calculate and forecast the "Cost per shared Bill" and "Cost per Standalone Bill" for Proposed 2013?
b) Please provide the cumulative CPI increase (or forecasted increase where applicable) from the outset of the 2009 OBA Settlement Agreement through December 31, 2012. Apply the cumulative CPI increase to the Cost per Shared Bill and the Cost per Standalone Bill and provide these figures
c) Please add the following columns of variance at the right of Table 4 titled "Proposed 2013 vs. 2011/2012" and "Proposed 2013 vs. 2009/2010". Provide these figures as a percentage.
d) For "Proposed 2013" vs. "2011/2012" comment on the proposed increases versus escalation in CPI.
e) For "Proposed 2013" vs. "2009/2010" comment on the proposed increases versus escalation in CPI.
f) "Fee per Shared Bill" and "Fee per Standalone Bill" increase by 4.5% and 2.8% respectively in Enbridge's proposal over the final year of the agreement. Please comment on these increases with reference to the previously negotiated settlement which prescribes an increase no greater than 2% per year.
g) Comment on the efficiencies achieved gained via Enbridge's new CIS, and why costs have grown at a higher rate than half CPI. Was there an expectation that efficiencies, or other factors, would have not necessitated an annual increase equivalent to CPI in the fees charges through Open Bill?

Witnesses: K. Lakatos-Hayward
S. McGill

RESPONSE

a) The "Cost per shared Bill" and "Cost per Standalone Bill" proposed by the Company for 2013 was the product of the Company's 2011 Billing and Billing Insert Services Cost Study noted at Exhibit D1, Tab 9, Schedule 1, paragraphs 19 through 24, a copy of this study can be found at Exhibit D1, Tab 9, Schedule 1, Appendix 3. The costs of the program were categorized as described in the noted exhibits and broken down as shown in the following tables:

Cost components of Shared Bills	**Cost per shared bill**
Customer Care Cost	$0.0626
CIS Functional	$0.0082
CIS IT	$0.0082
OBA Service Enhancement	$0.0062
ABSU	$0.5200
Total	***$0.6052***

Cost components of Standalone Bills	**Cost per standalone bill**
Customer Care Cost	$0.0626
CIS Functional	$0.0082
CIS IT	$0.0082
OBA Service Enhancement	$0.0062
Postage	$0.6000
ABSU	$0.8200
Total	***$1.5052***

b)

Year	**2009**	**2010**	**2011**	**2012****	**2013**
Annual CPI increase	1.30%	2.40%	2.30%	2.00%	
Cost per shared bill*	0.5112	0.5178	0.5303	0.5425	0.5533
Cost per standalone bill*	1.3454	1.3629	1.3956	1.4277	1.4563

Notes:
* Cost per bill of current year is calculated as cost of previous year escalated by CPI of the previous year.

** 2012 CPI change has been estimated based on average CPI of the last three years.

Witnesses: K. Lakatos-Hayward
S. McGill

c)

Billing Services Unit Costs & Fees

	--------- EB-2009-0043 Settlement ----			Proposed	Proposed 2013 vs. 2012	Proposed 2013 vs. 2010
	2009 /2010	2010 / 2011	2011/ 2012	2013		
Cost per Shared Bill	$0.5112	$0.5112	$0.5112	$0.6052	11.56%	16.87%
Cost per Standalone Bill	$1.3454	$1.3454	$1.3454	$1.5052	5.43%	10.44%
Fee per Shared Bill	$0.8800	$0.8930	$0.9000	$0.9410	3.79%	6.24%
Fee per Standalone Bill	$2.0500	$2.0800	$2.0980	$2.1570	2.13%	4.54%

d) The single most significant cost incurred by the Company in the provision of open bill services are fees charged to the Company by Accenture in support of the service. These fees were included as part of the Accenture Customer Care Services Agreement (the "CCSA") negotiated by the Company and Accenture in 2007 and extended in 2011. These fees have and are expected to continue to grow at a rate greater than that of the annual CPI. Also, please see the Company's response to Board Staff Interrogatory #7 at Exhibit I, Issue D11, Schedule 1.7 and Board Staff Interrogatory #4 at Exhibit I, Issue D11, Schedule 20.4.

e) Please see the Company's response to part (d) of this question.

f) After several years of experience in the operation of the open bill program the Company believed it appropriate to update the open bill cost study in 2011. The findings of this study indicated that in order to properly address the cost of the program and at a minimum retain the past level of ratepayer benefit and return to the Company it would be necessary to increase OBA fees for 2013 as proposed by the Company in this proceeding.

g) The main advantages of the Company's new CIS as compared to the Company's legacy CIS in respect of open bill has been the ability add the charges of more billing clients. With respect to Enbridge operating efficiencies, there is little opportunity for any such gains to outweigh the costs incurred, in respect of open bill related services provided by Accenture under the CCSA. The Accenture open bill costs outweigh Enbridge's internal costs associated with the program to the point where any marginal internal productivity gains would not result in overall reductions in program costs.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p10 and Appendix 3
Were any of the parties to the first Open Bill consultative consulted as part of the preparation of this report? Alternatively, did the Open Bill consultative, or a sub-group thereof, review the Inqvis report and provide comment on the report's findings? If so, please file any such comments from the consultative members.

RESPONSE

No, the parties to the first Open Bill consultative were not formally consulted as part of the preparation of the Inqvis report. With respect to the changes to the Open Bill Services Agreement outlined in Company's updated evidence, the Company has solicited written comments from all current Open Bill Services clients. The Company is currently in the process of reviewing these comments and may take them into consideration as part of the process of finalizing the standard form of Open Bill Services Agreement for 2013. The Company's response to such comments will take into account the fact that the contract changes for 2013 are being implemented to protect Enbridge's corporate reputation, maintain customer satisfaction with the program and address issues that have been experienced in connection with questionable sales and contracting practises that have been perpetrated by some open bill service clients.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p10 and Appendix 3
Enbridge states that, "The [Inqvis] study took into account fees payable by Enbridge to Accenture under the extended Customer Care Services Agreement (CCSA)…"

Please provide further details of the cost implications of the CCSA on any Open Bill Service agreement entered into subsequent to December 31, 2012.

RESPONSE

Based on the unit fees pertaining to Enbridge customers having Open Bill Service amounts billed on their Enbridge accounts set out in the extended and amended Customer Care Services Agreement between EGD and Accenture Business Services for Utilities Inc., the annual unit fee per Open Bill customer where a shared bill is employed will be $6.24 and where a standalone bill is employed will be $9.84. From 2013 to 2017 these fees increase on average each year by 1.32% and 1.91% respectively. The updated Accenture fees have been reflected in the Open Bill program's fees for 2013.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref(1): Ex D1/T9/S1/p6/Table 1
Ref(2): Ex D1/T9/S1/p7/para16

a) Does Table 1 assume the expected loss of Enbridge's sole ex-franchise customer and the loss of $200,000 at Ref(2)?

b) Has Enbridge updated the evidence at Exhibit C3, Tab 1, Schedule 1, page 4 pursuant to the expected loss of the sole ex-franchise customer?

c) In column "Budget 2013" at row "Enbridge Earnings Share". Please provide reasons for the ($233,864) variance over 2012 estimate, and if this is related to the

d) Please recreate Table 1 as if the terms of the 2009 Open Bill Settlement Agreement continued through December 31, 2013 applied to creation of the column titled "Budget 2013". Please state any assumptions made in assembling this forecast.

RESPONSE

a) Yes, Table 1 does assume the loss of Enbridge's sole ex-franchise customer and the associated reduction in program earnings in 2012 and approximately $200,000 for 2013.

b) No, Enbridge has not updated the evidence at Exhibit C3, Tab 1, Schedule 1, page 4. This change was already known and reflected in the Company's originally filed evidence.

c) The decrease in the Enbridge Earnings Share is due to termination of ex-franchise billing services in 2013 and to a lesser extent, higher external support costs.

Witnesses: K. Lakatos-Hayward
S. McGill

d) Please see the Table 1, revised as requested below.

Billing Services Contribution Margin & Earnings Sharing

	Actual				Estimate[1]	Estimate	Budget[6]
	2007	2008	2009	2010	2011	2012	2013
Revenues							
Open Bill							
- Operating: In-franchise	$ 13,885,255	$ 14,241,428	$ 14,750,470	$ 16,190,147	$ 16,268,470	$ 16,993,961	$ 17,276,984
- Operating; Ex-franchise	$ -	$ -	$ 230,482	$ 915,612	$ 927,806	$ 795,464	$ -
- Bad Debt Recovery	$ 1,979,176	$ 2,119,294	$ 2,189,573	$ 2,686,892	$ 2,570,934	$ 2,570,048	$ 2,567,593
- Ex-franchise Postage Recovery			$ 90,313	$ 252,943	$ 283,034	$ 247,800	
Total Revenues	**$ 15,864,431**	**$ 16,360,722**	**$ 17,260,839**	**$ 20,045,594**	**$ 20,050,245**	**$ 20,607,273**	**$ 19,844,576**
Expenses							
Open Bill							
Total Expenses	**$ 9,637,330**	**$ 10,428,763**	**$ 10,962,981**	**$ 12,563,756**	**$ 13,081,526**	**$ 13,784,698**	**$ 13,232,809**
Net Income	$ 6,227,101	$ 5,931,959	$ 6,297,858	$ 7,481,838	$ 6,968,719	$ 6,822,575	$ 6,611,767
Start-up Cost Recovery[2]	$ 656,174	$ 670,420					
Enbridge Earnings Share	$ 328,088	$ 348,602	$ 880,356	$ 1,840,306	$ 1,385,782	$ 1,325,566	$ 1,222,163
Ratepayer Benefit[4]	$ 5,389,604	$ 5,389,604	$ 5,417,502	$ 5,641,532	$ 5,582,937	$ 5,497,009	$ 5,389,604
Variance Account	$ (146,765)	$ (476,667)					
OBA Deferral Account[3]			$526,150.14				

Notes:

-1) 2011 is based on 8 & 4 forecast

-2) $0.04 per Bill as per 2007 Open Bill Access Settlement Agreement

-3) 2008 OBA deferral balance $309,370 is included in 2009 OBA DA balance

-4) Ratepayer Benefit includes both the base amount of $5.389 million, plus annual differences recorded in the Open Bill Deferral and Variance Accounts.

-5)Other costs include deferral & variance account amortization from 2010-2012

-6) Budget 2013 is based on the current Open Bill Services Agreement forecast of annual fee increase of 50% of CPI and was updated as below:

a) 2012 per bill fee was updated to refelect the actual fee in 2012 as opposed to previously filed fee of $0.900 & $2.098 per shared & standalone bills

b) Accenture contract unit costs were used for 2013 and the other 2012 Costs were inflated by the 2012 estimated CPI, 1.97% for 2013.

c) 2012 CPI estimate of 1.97% is based on simple average of last three years' CPI in the 12 months to November.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p5/para13

Enbridge states that, "the number of active billing clients growing from sixteen at the end of 2008 to forty-five as of December 2011" and that there is, "no recognition of billing volume or provision for a start-up charge".

Please comment on the intended purpose of the Open Bill, and whether Enbridge believes that it would be appropriate to charge smaller clients a higher fee on the basis of lower volumes?

RESPONSE

The purpose of Open Bill is to offer the convenience of a monthly consolidated energy services bill for Enbridge customers and generate economic benefits through the use of a shared Enbridge bill that can be shared between the Company's customers and its shareholders. In order to eliminate any opportunity for the Company to provide preferential treatment to any particular Open Bill Service client the same contractual provisions apply to all.

Enbridge does believe that it would be reasonable to consider charging smaller clients a higher fee on the basis of lower volumes as a means of reducing the potential for larger clients to subsidise smaller users of the service, however, this treatment is not consistent with the current Open Bill Service regulatory settlement. While the Company does not propose such a change at this time, it may consider it for the future.

Witnesses: K. Lakotos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p1

The ratepayer share has remained unchanged since 2009. Is Enbridge proposing any change to the ratepayers guaranteed share of $5,389,604? Please provide reasons why Enbridge has not sought to increase or decrease the amount of the ratepayer share

RESPONSE

The ratepayer share of Open Bill Service benefits for 2009 was $5,417,502, $5,641,532 in 2010 and was forecast to exceed the $5,389,604 base level in 2011and 2012 (Exhibit D1, Tab 9, Schedule 1, Table 3). These benefit amounts were determined through the application of the sharing mechanism set out in the current open bill service regulatory settlement agreement which extends to the end of 2012. The Company proposes to proceed with the same earnings sharing mechanism for 2013. The Company views 2013 as a transitional year for this program and may propose changes to the Open Bill Services revenue sharing model for 2014. It also should be noted that while the base level of ratepayer benefit is expected to be maintained in 2013, sharing attributable to the Company's shareholders is forecast to decline.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p9/Table 3

a) Please indicate what "Shareholder Benefit" in the bottom right cell of this table would be without the expected loss the sole ex-franchise customer, and note any changes to other cells in Table 3 as a result.

b) Is it possible that Enbridge could acquire a new ex-franchise customer after August 2012?

RESPONSE

a) The Company anticipates that the "Shareholder Benefit" in the bottom right cell of this table would be approximately $200,000 greater, or $1,380,000 had the sole ex-franchise customer been retained for 2013. Other cells in Table 3 that would change in value based on this assumption for 2013 are both occurrences of "Ratepayer Benefit – Ex-Franchise" which would have both indicated approximately $200,000 and the "Combined Ratepayer Benefit" which would have increased to approximately $5,589, 604.

b) It is highly unlikely that Enbridge could acquire a new ex-franchise billing client after August 2012. Enbridge is not currently in discussions with any potential ex-franchise billing clients and given the lead time required to set up and operationalize a new ex-franchise billing client it is unlikely that a change of this nature would have any significant positive benefit on program earnings in 2013.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p9/Table 3

Enbridge states that, "[T]here will be no anticipated change in the contribution margin and ratepayer benefits as a result of [the fee change]…"

Please describe the sources or effects that could negatively or positively affect the contribution margin to the benefit or detriment of ratepayers and the Company.

RESPONSE

On a unit basis the majority of the program's costs are well established. However, any unexpected change in the costs of operating the Open Bill Service or any change in Open Bill Service revenues will negatively or positively affect the contribution margin to the benefit or detriment of ratepayers and the Company. Unanticipated costs for legal or other third party support services would negatively impact the financial results of the program. In terms of revenue either the addition or loss of include Open Bill Service clients, or more importantly, the number of customers that receive Enbridge bills that include Open Bill Service charges would have the greatest potential to impact program revenues and earnings.

Witnesses: K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #12

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Ex D1/T9/S1/p15/para32

The Company has proposed that the requested change to the Open Bill costs and fees be in effect at least one year, through December 31, 2013. The Company has not commented on any longer approval.

a) Please describe reasons that would compel this Board to approve a one, two, or three year change to the rates.
b) Would Enbridge be opposed to approval of rates for Open Bill that would be fixed for a period of:

1. Two years
2. Three years
3. Four years or greater

Please provide reasons why the company would support or oppose a longer period with fixed rates for Open Bill Service.

RESPONSE

a) The most likely reason that the Board would approve Open Bill Service fees beyond 2013 would be that the Company had brought forward a proposal to the Board requesting that approval. The Company's current rate application now under consideration by the Board only requests the approval of the continuance of Open Bill Service until the end of 2013.

   The Company is currently reviewing its Open Bill Service program. The result of this review will address whether the Company will continue to offer the program beyond the end of 2013, as well as the terms that would apply to continuation of the program. Until such a review is complete, the Company does not wish to consider any long term approval of Open Bill Rates.

Witnesses: K. Lakatos-Hayward
S. McGill

b) Please see the Company's response to part a) to this question.

Witnesses: K. Lakatos-Hayward
S. McGill

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: D1/T8/S1/p. 16

EGD is proposing that with respect to the Open Bill Revenue Variance Account that the net annual revenue amounts in excess of $7.389 be shared 50:50 with ratepayers and that a credit goes to EGD in the event that the net annual revenues are less than $4.889 million equal to the shortfall between actual net revenues and $4.889 million. What is the basis for these two numbers? Why are they still appropriate? Why should the revenues be shared with the utility shareholders if the ratepayers are paying for the assets used to generate the revenue?

RESPONSE

The basis for these figures is the EB-2009-0043 Open Bill Access Settlement Agreement that was agreed to by all parties to the Company's 2009 rate proceeding, EB-2008-0219, and all parties to the Open Bill Access consultative. This arrangement was subsequently approved by the Board. The 2009 Open Bill Service regulatory settlement calls for a base customer benefit of $5.389 million, which, has reduced Enbridge rates by at least $5.389 million in each year of the programs operation since 2007. The $4.889 million figure was agreed to as part of this settlement to provide a degree of relief for Enbridge in the event that the Company's largest Open Bill Service client, Direct Energy, exited the program. In such an event Enbridge would be exposed to the impact of the first $500,000 shortfall in program earnings. The $7.389 million figure was set and agreed to so as to allow Enbridge the opportunity to earn up to $2 million of billing and bill insert revenue before further benefit sharing with ratepayers would be triggered.

Enbridge believes that the Open Bill Service earnings sharing model continues to be appropriate as part of a continuation of the EB-2009-0043 Open Bill regulatory settlement agreement. For 2013 it is expected that customers will continue to enjoy the base program benefit of $5.389 million, with the Company assuming the risk of attaining any earnings beyond this amount up to next $2 million.

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill
R. Small

Ratepayers do not own the assets used to generate any Enbridge revenue. Ratepayers, the customers of Enbridge, pay for natural gas and gas distribution services provided to them by the Company. Open Bill Services are unique to Enbridge and provide Enbridge customers with the convenience of a monthly consolidated energy services bill and the lion's share of the economic benefits generated by the program. In exchange for the Enbridge share of Open Bill Service earnings the Company takes on the management responsibility for the administration of the program, incremental billing collection risk, and risk to the Enbridge brand and corporate reputation. As such, it is entirely appropriate that the shareholders of the Company receive some of the financial benefits of the program.

Witnesses: K. Culbert
K. Lakatos-Hayward
S. McGill
R. Small

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Ref: Exhibit D1, Tab 9, Schedule 1

a) Please update Table 1 to reflect actual data for 2011.

b) Please update Table 2 to reflect actual data for 2011.

c) Please update Table 3 to reflect actual data for 2011.

RESPONSE

a) Please see the revised version of Table 1 provided on the following page.

Witnesses: K. Lakatos-Hayward
S. McGill

Billing Services Contribution Margin & Earnings Sharing

	Actual					Estimate	Budget[6]
	2007	2008	2009	2010	2011	2012	2013
Revenues							
Open Bill							
- Operating: In-franchise	$ 13,885,255	$ 14,241,428	$ 14,750,470	$ 16,190,147	$ 16,386,791	$ 16,993,961	$ 17,752,608
- Operating; Ex-franchise	$ -	$ -	$ 230,482	$ 915,612	$ 983,087	$ 795,464	$ -
- Bad Debt Recovery	$ 1,979,176	$ 2,119,294	$ 2,189,573	$ 2,686,892	$ 2,691,760	$ 2,570,048	$ 2,567,593
- Ex-franchise Postage Recovery			$ 90,313	$ 252,943	$ 302,858	$ 247,800	
Total Revenues	**$ 15,864,431**	**$ 16,360,722**	**$ 17,260,839**	**$ 20,045,594**	**$ 20,364,496**	**$ 20,607,273**	**$ 20,320,201**
Expenses							
Open Bill							
Total Expenses	**$ 9,637,330**	**$ 10,428,763**	**$ 10,962,981**	**$ 12,563,756**	**$ 13,361,502**	**$ 13,784,698**	**$ 13,838,895**
Net Income	$ 6,227,101	$ 5,931,959	$ 6,297,858	$ 7,481,838	$ 7,002,995	$ 6,822,575	$ 6,481,306
Start-up Cost Recovery[2]	$ 656,174	$ 670,420					
Enbridge Earnings Share	$ 328,088	$ 348,602	$ 880,356	$ 1,840,306	$ 1,378,948	$ 1,325,566	$ 1,091,702
Ratepayer Benefit[4]	$ 5,389,604	$ 5,389,604	$ 5,417,502	$ 5,641,532	$ 5,624,047	$ 5,497,009	$ 5,389,604
Variance Account	$ (146,765)	$ (476,667)					
OBA Deferral Account[3]			$526,150.14				

Notes:

-1) 2011 is updated with actuals

-2) $0.04 per Bill as per 2007 Open Bill Access Settlement Agreement

-3) 2008 OBA deferral balance $309,370 is included in 2009 OBA DA balance

-4) Ratepayer Benefit includes both the base amount of $5.389 million, plus annual differences recorded in the Open Bill Deferral and Variance Accounts

-5)Other costs include deferral & variance account amortization from 2010-2012

-6) Budget 2013 is based on the Company's Open Bill Services proposal for 2013, as described in this evidence

Witnesses: K. Lakatos-Hayward
S. McGill

b) Please see the revised version of Table 2 below.

Bill Insert Contribution Margin & Earnings Sharing

	Actual					Estimate	Budget
	2007	2008	2009	2010	2011	2012	2013
Revenues							
- Operating	**$ 668,185**	**$ 484,158**	**$ 327,227**	**$ 218,378**	**$ 184,498**	**$ 114,000**	**$ 114,000**
Expenses							
Support (Internal Allocation)	$ 50,295	$ 30,967	$ 20,566	$ -	$ -	$ 25,927	$ 26,338
Other		$ 16,250	$ 34,179	$ 39,136	$ 39,227	$ 40,040	$ 41,642
Total Expenses	**$ 50,295**	**$ 47,217**	**$ 54,745**	**$ 39,136**	**$ 39,227**	**$ 65,967**	**$ 67,980**
Net Income	**$ 617,890**	**$ 453,191**	**$ 306,661**	**$ 218,378**	**$ 184,498**	**$ 88,073**	**$ 87,662**
Enbridge Earnings Share[2]	$ 308,945	$ 226,596					
Ratepayer Benefit[2]	$ 308,945	$ 226,596					
Less: Research cost		$ 19,250					
Net Ratepayer Benefit		$ 207,346					

Notes:
-2) as per 2007 Bill Insert Settlement Agreement (50% / 50% Sharing of net bill insert margin between EGD & Ratepayers). Revised by 2009 Settlement Agreement to be rolled in with Open Bill Access Margin for sharing determination.

Witnesses: K. Lakatos-Hayward
S. McGill

c) Please see the revised version of Table 3 below.

Billing Services & Bill Insert Benefits Summary

	Actual					Estimate	Budget
	2007	2008	2009	2010	2011	2012	2013
Total Operating Benefit							
Billing Services	$ 6,227,101	$ 5,931,959	$ 6,297,858	$ 7,481,838	$ 7,002,995	$ 6,822,575	$ 6,481,306
Less: Ex-Franchise Net Income			$ (55,796)	$ (503,856)	$ (468,886)	$ (214,809)	
Bill Insert	$ 617,890	$ 453,191	$ 306,661	$ 218,378	$ 184,498	$ 88,073	$ 87,662
Total - Re. In-Franchise Sharing	$ 6,844,991	$ 6,385,150	$ 6,548,722	$ 7,196,361	$ 6,718,607	$ 6,695,839	$ 6,568,968
Extended Sharing Threshold			$ 7,389,604	$ 7,389,604	$ 7,389,604	$ 7,389,604	$ 7,389,604
Extended Ratepayer Sharing			$ -	$ -	$ -	$ -	$ -
Benefit Details							
Billing Services							
Ratepayer Benefit- In-Franchise	$ 5,242,839	$ 4,912,937	$ 5,389,604	$ 5,389,604	$ 5,389,604	$ 5,389,604	$ 5,389,604
Ratepayer Benefit- Ex-Franchise	$ -	$ -	$ 27,898	$ 251,928	$ 234,443	$ 107,405	$ -
Shareholder Benefit	$ 328,088	$ 348,602					
Bill Insert							
Ratepayer Benefit	$ 308,945	$ 207,346					
Shareholder Benefit	$ 308,945	$ 226,596					
Combined							
Ratepayer Benefit	$ 5,551,784	$ 5,120,283	$ 5,417,502	$ 5,641,532	$ 5,624,047	$ 5,497,009	$ 5,389,604
Shareholder Benefit Details							
Shareholder Benefit -Billing Services	$ 328,088	$ 348,602					
Shareholder Benefit -Bill Insert	$ 308,945	$ 226,596					
Total - Re. In-Franchise Sharing			$ 6,548,722	$ 7,196,361	$ 6,718,607	$ 6,695,839	$ 6,568,968
Ratepayer Benefit- In-Franchise			$ (5,389,604)	$ (5,389,604)	$ (5,389,604)	$ (5,389,604)	$ (5,389,604)
Ratepayer Benefit- Ex-Franchise			$ 27,898	$ 251,928	$ 234,443	$ 107,405	$ -
Shareholder Benefit	$ 637,033	$ 575,198	$ 1,187,016	$ 2,058,684	$ 1,563,446	$ 1,413,639	$ 1,179,364

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 5, Paragraph 13

In reference to the Open Bill Access ("OBA") program, the Applicant notes that;

> *"Economically, the program is challenged by… the requirement to charge all participants the same fee with no recognition of billing volume or provision for a start-up charge. As a result, revenues do not always recover cost associated with some of the program's smaller clients..."*

Exclusive of the Company's proposal for a start-up fee noted in Paragraph 39, has the Company considered a formula to specifically recover the overall costs of small volume Billers from small volume Billers specifically?

RESPONSE

Please see the response to Board Staff Interrogatory #8 at Exhibit I, Issue D11, Schedule 1.8.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 17, Paragraph 38

In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise Section 4.3 of the OBA Agreement to;

> *"…enable EGD to recover costs incurred to investigate and resolve customer disputes and potential breaches of the Open Bill Service Agreement by Billers…Such costs will be defined as corrective costs and include, but are not limited to outside legal advice, auditors, consultants and investigators engaged by the Company to investigate or follow-up on such breaches or potential breaches of the agreement."*

a) Please confirm that in the event the above noted activities demonstrate the Biller to be in full compliance with its obligations under the OBA Agreement and all applicable legislation/regulation the costs noted will be borne by the Company.

b) Please confirm that the above noted additional fee's will be limited to external costs and will not include internal costs incurred as part of the regular operation of the Open Bill Service.

RESPONSE

a) In the event that the efforts of the Company to investigate and resolve customer disputes and potential breaches of the Open Bill Service Agreement by a Biller as referenced above confirm, the Biller's compliance with the Open Bill Service Agreement and all applicable legislation/regulation, the Company will still seek to recover the costs related to these efforts from the Billers. The Company is of the view that this is a reasonable position to take in that it would have been the activities of the Biller that gave rise to the need for the investigative effort in the first instance.

b) The Company confirms that the above noted additional fees will be limited to the recovery of external costs.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 18, Paragraph 41

In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise the OBA Agreement to;

> *"…allow [the Company] to recover Biller charges from the Biller that are uncollectible from the customer after sixty (60) days in circumstances where the Biller is either unable, or unwilling to provide evidence to the Company that it has conducted a credit check for the customer in question…"*

a) Please outline how this change will affect the Bad Debt fee collected from Billers by the Company. Logically, this change will precipitate a reduction in the Company's overall exposure to Bad Debt. Will the Company lower the Bad Debt fee as a result of this reduced exposure?

b) The Company has not identified any intention to revise the OBA to require all customers to meet the Minimum Credit Rating identified in the Agreement. Rather, only customers on financing plans or whose aggregate charges to the Biller in any 12 month period exceed $1,800 CAD are subject to this requirement as per Section 2.6(l) of the Agreement. Please confirm that the Company's proposal for non-recourse against the Biller shall apply only to those customers identified as subject to the Minimum Credit Rating specified in the OBA Agreement.

RESPONSE

a) The change to Section 5.3 of the Open Bill Services Agreement referenced at Exhibit D1, Tab 9, Schedule 1, page 18, Paragraph 41 can be found at Exhibit D1, Tab 9, Schedule 1, Appendix 5, page 19. This change provides the Company with recourse against the billing services client in the event that they cannot confirm that they have meet their obligations with respect to a particular customer account as set out in Section 2.6 (l) of the Agreement, Exhibit D1, Tab 9, Schedule 1, Appendix 5, page 11. The Company does not believe that this change will have any significant impact on bad debt exposure nor was the bad debt fee ever intended to cover such charges in dispute. Given the process for the annual revision of "Scheduled

Witnesses: K. Lakatos-Hayward
S. McGill

Settlement" as defined in Appendix B, Exhibit D1, Tab 9, Schedule 1, Appendix 5 to the Open Bill Services Agreement, any reduction in the Company's overall bad debt experience would tend to increase the value of the Scheduled Settlement, in turn reducing bad debt exposure for the Company's open bill service clients.

b) In Exhibit D1, Tab 9, Schedule 1, Appendix 5 to the Open Bill Services Agreement, Section 2.6(l) applies on a customer specific basis, as does the associated recourse available to the Company under Section 5.3 of the Agreement. However, Section 8.6 (d) of the Agreement found at Exhibit D1, Tab 9, Schedule 1, Appendix 5, page 32 identifies the failure of the billing services client to meet its obligation under Section 2.6(l) of the Agreement as an act of default under the Agreement.

JUST ENERGY INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise the OBA Agreement to;

> *"…enable it to discontinue the billing of charges applicable to a customer service upon six months prior notice from the Company to the affected Biller(s)…"*

Please provide further explanation or examples of situations that may warrant the discontinuance of Biller charges.

RESPONSE

Sections 8.1, 8.4 and 8.5 of the Agreement found at Exhibit D1, Tab 9, Schedule 1, Appendix 5, pages 29 to 31 have been revised to eliminate the automatic roll-over provisions of its predecessor. Under the new form of agreement the contract term will be date specific with no predefined renewal rights and can be terminated by the Company at the expiry of the Term, or the then current renewal term upon six months prior notice. The Company would rely on this provision in the event that it chose to cease the provision of third party services generally, or in respect of a particular Billing Services client in the event that the Company was not satisfied with a party's performance under the Agreement.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 19, Paragraph 43
In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise the OBA Agreement to;

> *"…allow the Company the option to remove disputed Biller charges from the customer's bill immediately upon receipt of notice of the dispute by the customer…"*

a) Please outline how the Company intends to handle situations in which a Biller's charges for a customer have been removed from the bill at the onset of Dispute Resolution, but the Biller is later found to have honoured their obligations to the customer and their obligations to the Company under the OBA Agreement.

b) The Company states it will remove the disputed Biller charges immediately upon receipt of notice of the dispute by the customer, how quickly will the charges be returned to the bill once the dispute has been resolved?

c) The Company states it shall be entitled to refund to the relevant Customer the full amount of any At-Issue Receivable. When does the Company propose the refund would take place, e.g. prior to reviewing the dispute to determine if it is valid or after?

RESPONSE

a) In the event that the billing services client resolves the dispute with the customer after the charge for the product or service in question has been removed from the customer's account by the Company, the process to restore the charge(s) for billing would require the billing services client to contact the Biller Hotline to give notice of the resolution of the dispute. Biller Hotline personnel would then remove the billing block for the Bill Type Code associated with the product or service in question for that billing services client. The billing services client would then submit a Bill Ready or Rate Ready Add transaction to the Company via the Open Bill Interface to restore the charge to the customer's Enbridge account.

Witnesses: K. Lakatos-Hayward
S. McGill

b) If the dispute is resolved as per a) above then the charge would appear on the Customer's next invoice after the addition of the charge.

c) As set-out in Section 7.6 of the Open Bill Services Agreement (Exhibit D1, Tab 9, Schedule 1, Appendix 5, pages 25 through 27) the billing services client will have either 15 or 45 days to work with the customer to resolve the disputed amount. If the disputed amount is not resolved before the required dispute resolution due date the Company will perform a manual adjustment to return the disputed amount to the customer.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 19, Paragraph 43

In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise the OBA Agreement to reduce the timeframe for dispute resolution from sixty (60) days to forty-five (45) days.

Will the Company consider a shorter timeframe for Dispute Resolution of thirty (30) days?

RESPONSE

Given the other changes to Section 7.6 (c) of the Open Bill Services Agreement (Exhibit D1, Tab 9, Schedule 1, Appendix 5, page 25) the Company is of the view that in instances where the Company has elected not to immediately remove the at issue charges from the customer's account that the forty-five day dispute resolution period is reasonable. The Company is prepared to consider moving to a thirty day dispute resolution period. It should be noted however, that under Section 7.6 (d) the dispute resolution period is reduced to fifteen days should the matter of the dispute be within the scope of the Ontario Consumer Protection Act.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 21-22, Paragraph 50

In reference to the Open Bill Access ("OBA") program, the current Agreement allows that the Company may implement certain mitigation efforts in the event of a Biller default including but not limited to the suspension of Billing Services or the suspension of the addition of any new customers for which Billing Services have been requested. The Application has stated its intention to revise the OBA Agreement;

> *"…such that the imposition of such limitations will be at the sole discretion of the Company."*

Please provide an explanation for this change in rights under the OBA Agreement.

RESPONSE

Under the current form of Open Bill Services Agreement the only avenue open to the Company to address a default under the Agreement on the part of a billing services client is to terminate the Agreement. In practice, however, the current contract provides the billing service client with the ability to cure defaults on a one off basis and the threat of contract termination has not been effective in encouraging some billing service clients to implement lasting cures to underlying problems giving rise to defaults. The other rights of the Company in the event of billing services client default set out in Section 8.8 of the Agreement (Section 8.8 of the Open Bill Services Agreement (page 33 of 43, Exhibit D1, Tab 9, Schedule 1, Appendix 5) are voluntary in nature and have also not been an effective means of addressing issues giving rise to defaults under the current form of agreement.

The revised form of Agreement will give the Company the ability to impose one of the lesser actions described in Section 8.8 of the Agreement, which in most cases will allow a billing services client to continue to subscribe to billing services on a limited basis while the issues giving rise to the default are resolved. The Company is of the view that making the actions described in Section 8.8 of the Agreement a practical alternative will

Witnesses: K. Lakatos-Hayward
S. McGill

result in a more equitable means of addressing billing service client default situations as opposed to the outright termination of the Agreement and to ensure existing customers are not stranded during this process.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Pages 19-20, Paragraph 45

In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise Section 8.1 of the OBA Agreement to remove the automatic roll-over provision, instead entering into the Agreement for a defined term with the intention of offering only one year terms effective January of 2013.

a) Please confirm that this change will not affect the day-to-day operations of the OBA program generally. Specifically, please confirm that while the Agreement may be renewed annually, Biller charges for individual customers will not need to be re-submitted annually.

b) Please confirm that Biller charges will continue to be amendable within the one year Agreement term.

c) Please outline the process for renewal of a one year OBA Agreement. Specifically, will Billers be required to submit a full re-application or will a modified renewal process be put in place?

d) Please outline the modified renewal process if applicable.

e) How far in advance could Agreement renewals/re-applications be submitted to the Company?

f) As the majority of the agreements and contracts the Biller has with its customers are for a period longer than one year please confirm that this will not pose an issue.

g) Has the Company considered 2, 3, 4, or 5 year Agreement terms? Please explain why these terms lengths are or are not acceptable.

Witnesses: K. Lakatos-Hayward
S. McGill

RESPONSE

a) The Company does not anticipate that the removal of the automatic roll-over provision from Section 8.1 of the Open Bill Services Agreement will have any significant effect on the day-to-day operations of the OBA program. Billing service client charges for individual customers will not need to be re-submitted annually. The Company does not anticipate a requirement for the billing services client to provide a full contract re-application.

b) Please see the Company's response to part a) of this interrogatory.

c) It is expected that the open bill service clients will enter into the revised form of Open Bill Services Agreement to become effective from January 2013. The Company anticipates that any future annual contract renewal / re-contracting process for Open Bill Service Agreements will be similar to that followed in the past.

d) Please see the Company's response to part c) of this interrogatory.

e) The Company anticipates that the annual renewal process for Open Bill Service Agreements will begin three to six months prior to the expiry of the current billing services agreement with each client.

f) The Company anticipates being able to provide billing service clients notice of contract renewal or termination in advance of the expiry dates of their current agreements. This timing should provide for the uninterrupted provision of billing services throughout the transition from one contract to the next. The Company will be able to accept third party customer charges that extend for a time beyond the term of the Open Bill Services Agreement.

g) The Company has moved to a one year term of agreement as the Open Bill program is currently the subject of internal review. Given that there is the potential to terminate and wind down the program the Company does not view it prudent to enter into Open Bill Services Agreements with terms extending beyond the end of 2013 at this time. Provided that the Company decides to continue to offer third party billing services beyond the end of 2013 it will revisit the potential for longer term Open Bill Service Agreements. Also, please see the response to Board Staff Interrogatory #12 at Exhibit I, Issue D11, Schedule 1.12.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Page 20-21, Paragraph 46, 47

In reference to the Open Bill Access ("OBA") program, the Applicant states its intention to revise the OBA Agreement so that;

> *"…the Biller will be in Default of the OBA Agreement in the event that the Biller fails to perform or observe its obligations set out in the Agreement on three (3) or more occasions in any twelve (12) month period, regardless of whether any such failures have been remedied…"*

a) Has the Company considered whether the impacts of this change will disproportionately affect OBA Billers with large customer bases? By way of example, a hard rule of three (3) instances as noted above may discriminate against a Biller with one hundred thousand or more customers when compared to a Biller with only five hundred customers.

b) Will the Company consider a scalable approach to determining the number of above noted instances that should warrant placing the Biller in a Default position? Specifically, would the Company consider generating the number of instances that shall deem the Biller to be in Default as a percentage of the Biller's overall customer base?

c) Please further outline the guidelines for determining when such instances noted in Paragraph 47 will be deemed to have occurred absolutely.

d) Please provide further explanation on when a name restriction will be considered to have been violated absolutely, given the often contradicting and circumstantial evidence that supports claims of this nature.

e) Please confirm that the instances of performance or obligation failure listed in Paragraph 47 represent the full list of instances that could bring about a Biller's Default under this revision. If the list provided is not comprehensive, please provide a full list.

Witnesses: K. Lakatos-Hayward
S. McGill

RESPONSE

a) Yes, the Company considered whether the impacts of this change will disproportionately affect Open Bill Access ("OBA") Billers with large customer bases. The Company has introduced this provision to the Open Bill Services Agreement to address the systemic nature of the default / cure process supported by the current form of contract. The Company needs some mechanism that ensures that either the practices giving rise to the defaults are permanently cured, or that the continued occurrence of defaults under the agreement leads to a clear path to the removal of the defaulting party's charges from the Enbridge bill within a reasonable period of time. The Company expects that its billing services clients will act expeditiously to implement effective lasting cures to address the businesses practices that give rise to any defaults of the agreement that have been identified by the Company. As such, a responsible party should never find itself in a position where it has come into default under the agreement on multiple occasions. Further, the revised Open Bill Services Agreement will provide the Company with the right to terminate the agreement where three occurrences of billing services client default have been identified, however, this right can either be waived or extended time can be granted by the non-defaulting party to enable the implementation of an effective and lasting cure for the issue giving rise to the default.

b) Please see the Company's response to part a) of this interrogatory.

c) Before the Company issues a notice of default under an Open Bill Services Agreement, a thorough investigation is undertaken to confirm that a default under the agreement has in fact occurred. It is the Company's practice to follow-up and interview affected customers, review billing service provider documentation including consumer agreements and sales materials and review voice recordings of customer sales confirmation telephone conversations. It is the Company's intention to continue these practices and document the results of such investigation and analyses. Any notice of default under the agreement will be substantiated through such documentation.

d) Please see the Company's response to part c) of this interrogatory.

e) The instances of performance or obligation failure listed in paragraph 47 of Exhibit D1, Tab 9, Schedule 1, updated June 8, 2012 represent a summary of the actions that may constitute an instance of default under the Open Bill Services Agreement. For a detailed description of these contract provisions please see Section 8.6 of the Open Bill Services Agreement at Exhibit D1, Tab 9, Schedule 1, Appendix 5, pages 31 through 33.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1, Appendix 1, Page 4

In the above noted reference, in reference to the Board's previous Settlement Proposal on this matter, the Board has stated;

> *"The Settlement Proposal before the Board is the result of a lengthy and involved negotiation among the members of the consultative group…The Board's own process confirmed that there is no opposition to the Settlement Proposal."*

Please outline the steps that have been taken and results that have been generated to demonstrate that affected parties, with a particular emphasis on Billers under the OBA Agreement, have no opposition to the Company's proposed changes to the OBA fee's and OBA Agreement.

RESPONSE

Please see the responses to Board Staff Interrogatories #1, 2, 3 and 5 at Exhibit I, Issue D11, Schedules 1.1, 1.2, 1.3, and 1.5

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9, Schedule 1

a) What prior notice will the Company provide to Billers of changes to fees and the scheduled settlement percentage in the future?

b) Will the scheduled settlement percentage change in January of 2013?

RESPONSE

a) As set out in Appendix B (Open Bill Services Agreement at Exhibit D1, Tab 9, Schedule 1, Appendix 5, Appendix B) of the Open Bill Service Agreement the Company will, as it has in the past, provide notice to all billing clients of the annual changes to the Billing Fee and Scheduled Settlement which are both effective from the first day of January each year. As a practical matter the Company cannot provide prior notice of the changes in these items as historic information from the preceding calendar year is required to calculate both the Billing Fee and Scheduled Settlement. Again, as in the past, the Company will endeavour to provide notice of the revised figures at the earliest possible date.

b) Yes, the Company expects that the Scheduled Settlement percentage will change in January 2013 in accordance with the terms of Appendix B to the Open Bill Services Agreement.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #12

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference Exhibit D1, Tab 9 Schedule 1 Appendix 5, Article VI Changes and Modifications 6.1 (c)

In reference to the Open Bill Access ("OBA") program proposed changes, the Applicant states its intention to revise the OBA Agreement wording as follows:

> *"so that In the case of a proposed change to the products and/or services included as*
> *Customer Services, a Customer Service will not be removed from the list of Customer Services, if such Customer Service is being offered by any Biller to any of its Customers, without six (6) months prior notice from the Company,"*

a) Please provide a full explanation of what the process is for determining if a product and/or service should be included as a Customer Service.

b) Please provide a full explanation of whom and what process would be used to determine if a product and/or service should be removed as a Customer Service.

RESPONSE

a) The Company will assess and determine whether a product or service will be accepted as a customer service for which charges can be invoiced on the Enbridge Bill based on the nature of the product or service, the relationship between such product or service and natural gas and energy distribution services, and the acceptability of such product or service to Enbridge and its customers based on customer feedback, complaints and comment.

b) The determination of what products or services are to be added or removed for billing on the Enbridge bill will be made by Enbridge and will take into account the factors noted in the Company's response to part a) of this interrogatory.

Witnesses: K. Lakatos-Hayward
S. McGill

JUST ENERGY INTERROGATORY #13

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Is the Company committed to providing the OBA service long-term? What does the Company define as long-term?

RESPONSE

Please refer to the Company's response to Board Staff Interrogatory #12 at Exhibit I, Issue D11, Schedule 1.12. As part of this application the Company has requested that the Board approve the Company's provision of third-party billing services to the end of 2013. The Company would define "long term" in the context of open bill services as a period of greater than one year. As indicated in the Company's response to Exhibit I, Issue D11, Schedule 1.12 the open bill program is under review by the Company and a determination as to whether or not Enbridge will offer open bill services beyond 2013 will be made later this year, and if so, on what basis, terms and conditions.

If the service is not be extended beyond the end of 2013, the Company will work closely with its billing services clients in accordance with the termination transition services set-out in Section 8.9 (Open Bill Services Agreement at Exhibit D1, Tab 9, Schedule 1, Appendix 5, pages 34 and 35) of the Open Bill Services Agreement to facilitate an orderly transition of third-party charges off of the Enbridge bill in an orderly manner such that it mitigates any potential negative impacts on Enbridge customer, billing services clients and the Company. It is expected that the time required to complete such a transition for all billing services clients would extend well into 2014 and potentially beyond.

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 5 paragraph 13.

Over the past two years, the Billing Services Program has performed reasonably well, with the number of active billing clients growing from sixteen at the end of 2008 to forty-five as of December 2011.

a) Please provide the average number of bills in any particular month for each of the active billing clients. For the purposes of the response please correct for factors that would skew the average, for example if an active billing agent has been technically active for 2 years, but only reached a plateau of activity at the end of the first year, we would expect that the start up "slow" months would not be included in the average.

RESPONSE

a) The table below provides the average number of monthly bills for each active open bill service client. The Average was calculated over the past 12 months. It should be noted that 10 of the current 46 open bill service clients have not billed any charges on the Enbridge bill in the past 12 months; as such, their figures were not included in this presentation.

Witnesses: K. Lakatos-Hayward
S. McGill

Biller #	# of Accounts	Biller #	# of Accounts	Biller #	# of Accounts
1	1,218,439	13	2,222	25	56
2	111,555	14	2,019	26	42
3	33,365	15	1,457	27	41
4	22,753	16	1,095	28	39
5	12,902	17	631	29	32
6	11,375	18	523	30	17
7	8,355	19	357	31	14
8	5,425	20	260	32	13
9	4,966	21	247	33	6
10	4,637	22	68	34	3
11	3,385	23	65	35	3
12	3,331	24	59	36	3

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 5 Paragraph 14

From a customer standpoint, the Billing Services Program has also functioned well. Third party charges appear on approximately 1.4 million Enbridge bills each month. Customer research conducted by the Company in 2011 indicates that the majority of customers value the convenience of consolidating their energy related charges on their Enbridge bill and appreciate that this program helps to reduce their gas distribution charges.

a) Please provide a table for the years 2007 to 2013 that shows, on an actual or forecast basis as appropriate:

   a) the volume of Shared Bill charges per year,
   b) the volume of Stand Alone Bill charges per year, and
   c) the volume of Ex-Franchise Bill charges per year.

By way of example, we would expect the annual volume of Shared Bill charges to be in the order of 16.8 Million based on the approximately 1.4 million monthly charges noted in paragraph 14.

b) Please provide the customer research conducted by the Company in 2011.

RESPONSE

a)

Annual Volume	2007	2008	2009	2010	2011	2012*	2013**
a). Shared Bill	15,893,659	16,119,712	16,316,310	16,891,269	16,927,458	17,534,438	17,554,438
b). Stand Alone Bill	510,735	621,276	573,093	479,492	463,739	430,084	430,084
c). Ex-Franchise Bill	-	-	161,639	455,658	523,473	420,000	-

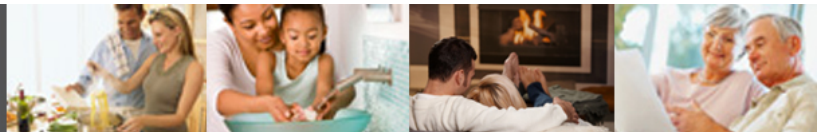
* Based on 2012 OBA Budget

** Based on 2013 OBA Budget

b) Please see attached.

Witnesses: K. Lakatos-Hayward
S. McGill

ENBRIDGE
CUSTOMER FORUM



Third Party Billing Customer Research 2011

Final Results

Study Background:

Enbridge currently provides a third-party billing service (Open Bill) for energy service providers who wish to bill for products and services on the Enbridge bill. Examples of products and services include rental water heaters and other rental equipment, finance contracts, equipment insurance warranty and protection plans, carbon offsets, etc. There are currently 34 companies participating.

Research Purpose and Objectives:

The main purpose of the research is to determine the overall acceptability of third party billing. Objectives include:

- To assess whether customers view third party billing positively or negatively,
- To determine whether customers associate a value to the Enbridge brand in the context of third party billing.
- To understand if customers are aware of the economic and environmental benefits associated with third party billing.

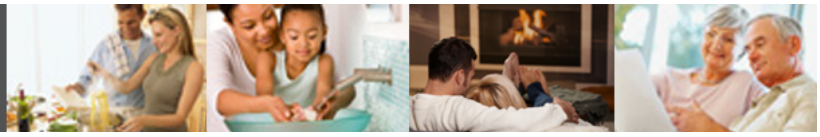
Fieldwork Stats

Start Date: 2011-06-24
End Date: 2011-07-20

Invited: 1,170
Completed: 367

Completion Rate: (Completed / Invited): 31%

ENBRIDGE CUSTOMER FORUM



Third Party Billing Customer Research 2011

Final Results

Enbridge bill responsibility

Q1. Are you either primarily or jointly responsible for paying your natural gas bill?

	Count	Percent
Yes	367	100%
No	0	0%
Total	**367**	

→ Customers who responded "No" (they are not primarily or jointly responsible for paying their natural gas bill) were terminated from completing the questionnaire.

Third Party Billing Services

Q2.Enbridge provides a third-party billing service whereby other energy service providers' charges appear on the Enbridge bill. Please select the types of charges that appear on your monthly Enbridge bill for products or services provided by other companies or organizations?

	Count	Percent
Hot water heater rental	349	95%
Heating or Air Conditioning insurance warranty or protection plan	74	20%
Equipment rentals (other than hot water heater)	9	2%
Finance contracts	8	2%
Carbon Offsets	3	1%
Other (specify)	13	4%
None of the above	0	0%
Not sure	0	0%
Total	**367**	

→ "Other" responses include *Gas Fireplace Maintenance*, *Plumbing Protection Plan*, *Total Home Protection Plan*, and *Appliances Protection Plan.*

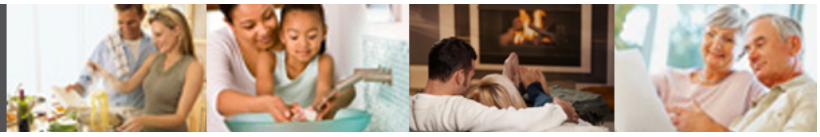
→ Customers who responded "none of the above" or "not sure" were terminated from completing the questionnaire.

Sample Composition:

The 367 customers in the sample are those customers who have some responsibility for paying their Enbridge bill, and subscribe to at least one third party billing service.

For the purposes of this report, third party billing service customers who participated in this research study will simply be referred to as "customers."

ENBRIDGE
CUSTOMER FORUM



Third Party Billing Customer Research 2011

Final Results

Image Quality

Q3. How would you rate the overall quality of Enbridge Gas Distribution and the services it provides?

	Count	Percent
Excellent	87	24%
Very good	150	41%
Good	84	23%
Neutral (neither good nor poor)	29	8%
Fair	7	2%
Poor	5	1%
Very poor	2	1%
Don't know	3	1%
Total:	**367**	

} 65% *excellent* or *very good*

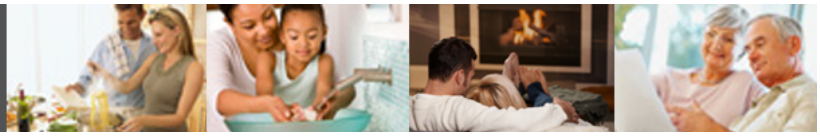
65% of Third Party Billing customers rated the overall quality of Enbridge as *excellent* or *very good.*

- This compares to 51% of residential customers without a particular interaction.[1]
- Results are similar for eBill customers when compared to paper-billing customers.

Source:

[1] Customer Satisfaction Research 2011 (YTD results as of Q2), General segment.

ENBRIDGE CUSTOMER FORUM



Third Party Billing Customer Research 2011

Final Results

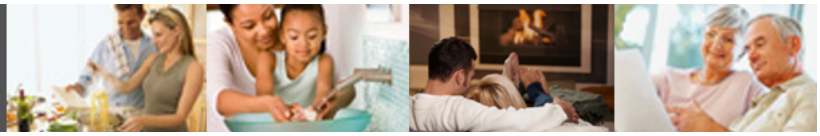
Third Party Billing Perceptions

Q4 Please tell me whether you strongly agree, somewhat agree, somewhat disagree or strongly disagree with each of the following statements.

Customers clearly prefer to have their energy related services consolidated on one bill (87%), and agree that it impacts their buying or renting decisions (63%). There is confusion around the relationship Enbridge has with Third party billers; only half (48%) are aware that Enbridge is not affiliated with energy service providers included on the Enbridge bill. Even fewer (43%) are aware that Enbridge does not support or endorse these services.

	Total Agree	Strongly agree	Somewhat agree	Somewhat disagree	Strongly disagree	Not sure
Consolidating all my energy related services into one bill is a convenience for me.	**87%**	50%	37%	7%	4%	2%
Consolidating all my energy related services into one bill saves waste and is more environmentally friendly.	**86%**	50%	36%	6%	4%	4%
The ability to be billed for and pay charges for non-Enbridge energy related services on my Enbridge bill is important to my buying / renting decisions.	**63%**	24%	39%	14%	11%	11%
A non-Enbridge energy service provider who can add their charges to my Enbridge bill is more trustworthy than those that do not.	**55%**	17%	38%	13%	16%	16%
Enbridge is not affiliated with energy service providers that include their charges on my Enbridge bill.	**48%**	19%	29%	10%	9%	33%
Enbridge does not support or endorse the services that I obtain from the other energy service providers who include their charges on my Enbridge bill.	**43%**	20%	23%	13%	11%	33%
A non-Enbridge energy service vendor who can offer various payment methods is more likely to get my energy related business.	**40%**	13%	27%	23%	24%	13%
Questions about charges on my Enbridge bill from non-Enbridge energy service providers can be dealt with by contacting Enbridge.	**33%**	14%	19%	14%	23%	30%
Receiving separate bills from each energy service provider that I purchase a service from is preferable to me.	**18%**	5%	13%	29%	45%	8%

ENBRIDGE CUSTOMER FORUM



Third Party Billing Customer Research 2011

Final Results

Satisfaction with Third Party Billing service

Q5. Overall, how satisfied are you with the service of third-party billing provided by Enbridge?

	Count	Percent
Very satisfied	122	33%
Somewhat satisfied	151	41%
Somewhat dissatisfied	33	9%
Very dissatisfied	15	4%
Not sure	46	13%
Total	**367**	

} 74% *very or somewhat satisfied*

74% of Third Party Billing customers are *very satisfied* (33%) or *somewhat satisfied* (41%) with the third party billing service provided by Enbridge. 13% of customers are dissatisfied, and 13% are not sure.

Awareness of Billing Service Revenue

Q6. Were you aware that Enbridge uses the revenue gained from the third-party billing services to help lower delivery charges for all customers?

	Count	Percent
Yes	30	8%
No	337	92%
Total	**367**	

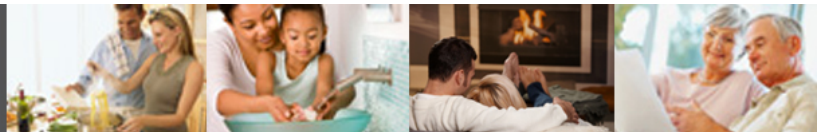
Most customers **(92%)** are not aware that customers benefit from lower delivery charges as a result of the revenue gained from the third party billing service.

Q7. Knowing that Enbridge uses the revenue gained from the third-party billing service to help lower delivery charges, how does this change your impression of Enbridge as a company?

	Count	Percent
Much more favourable	77	21%
Somewhat more favourable	190	52%
Somewhat less favourable	12	3%
Much less favourable	2	1%
No impact	86	23%
Total	**367**	

However, once realizing the benefit, **73%** said they had a more favourable impression of Enbridge as a company.

ENBRIDGE CUSTOMER FORUM



Third Party Billing Customer Research 2011

Final Results

Utility Bill Payment Preferences

Q8. When paying utility bills, what method of payment would you most prefer?

Paying online through the bank is the preferred payment method by more than half of customers (59%). Pre-authorized credit (17%) and pre-authorized debit (17%) are other preferred methods.

eBill customers are slightly more likely to use electronic methods (online, pre-authorized credit or debit) than paper-billed customers.

	Count	Percent
Online (through my bank)	216	59%
Pre-authorized credit card charge	64	17%
Pre-authorized debit	61	17%
Cheque by mail	10	3%
In-person (at my bank)	6	2%
Other (specify)	10	3%
Total	**367**	

Customers who stated “other” most often said they pay by credit card (not pre-authorized) or telephone banking.

Natural Gas Commodity Supplier

Q9.The natural gas industry is broken into two systems, supply and delivery. Enbridge delivers natural gas to all customers in their franchise area through their pipelines. The natural gas supply can also be provided by Enbridge or by another company (usually referred to as a broker or marketer). Who do you purchase your natural gas supply from?

	Count	Percent
Enbridge Gas Distribution	311	85%
Broker/Marketer	39	11%
Don’t know	17	5%
Total	**367**	

85% of customers believe they purchase their natural gas through Enbridge Gas Distribution. Although this is higher than the actual percentage of system gas customers (77%),[1] it is not significantly different than the percentage of Customer Forum panel members (82% are on system gas).[2]

[1] Source: Customer Care, May 2011

[2] Source: Business Intelligence, May 19, 2011

Third Party Billing Customer Research 2011

Final Results

Billing Type

Q. Do you receive a paper bill or an eBill (paperless billing) from Enbridge?

	Count	Percent
eBill (paperless billing)	224	61%
Paper bill	143	39%
Don't know	0	0%
Total	**367**	

The number of customers using eBill (61%) is over-represented, as only 5%[1] of residential customers overall are signed up for eBill.

[1]Source: Customer Care, June 2011

For further information, please contact:

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Public & Government Affairs
Enbridge Gas Distribution
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416-495-5287
Study Reference: CR-585

The results shown in this report are based on an online sample drawn from the Enbridge Customer Forum. Results may not be representative of the population universe and should be used as directional in nature only.

VECC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 6 Table 1 Note 4

a) Please describe the nature of the Open Bill Deferral and Variance Account credits that increased the Ratepayer Benefit beyond the embedded $5.389 million in the years 2009-2012. Please explain why these credits are forecast to cease in 2013.

RESPONSE

a) As per the Board's Accounting Order in EB-2009-0043 Appendix A, Section 7, the Ex-Franchise Third Party Billing Services Deferral Account was used to record the net annual revenues from the ex-franchise billing services which was shared on a 50/50 basis with ratepayers. It is these credits that increase the Ratepayer Benefit beyond the $5.389 million embedded in the Company's base rates in the years 2009 to 2012. Please see the Company's response to Board Staff Interrogatory #7 a) at Exhibit I, Issue D11, Schedule 7 regarding why these credits are forecast to cease in 2013.

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 13 paragraph 27
Exhibit D1 Tab 9 Schedule 1 Page 14 paragraph 9 Table 4

Specifically, for the purposes of determining net revenues from the Billing Services program for 2013, the Company proposes to adopt the costs identified in the 2011 Open Bill and Bill Insert Cost Study, applying the increase in cost for 2013 to both per bill unit costs and revenues, thereby maintaining the margin to be earned by these programs.

Table 4

Billing Services Unit Costs & Fees

	EB-2009-0043 Settlement			Proposed
	2009 / 2010	2010 / 2011	2011/ 2012[2]	2013
Cost per Shared Bill	$0.5112	$0.5112	$0.5112	$0.6052
Cost per Standalone Bill	$1.3454	$1.3454	$1.3454	$1.5052
Fee per Shared Bill[1]	$0.8800			

a) Please check whether the figure of $.6052 in Table 4 is correct, or whether it should be $.6524 pursuant to Exhibit D1 Tab 9 Schedule 1 Appendix 3 Page 11. If the figure of $.6052 is incorrect, please confirm that the error was not reproduced in any other Tables or implicitly in calculations underpinning Enbridge's proposal. If the figure of $.6052 is correct, please provide the references for the evidence underpinning that figure.

b) While the statement at paragraph 27 asserts that the increased costs reflected in the 2011 Cost Study are proposed to be included in the increase for both the costs and

Witnesses: K. Lakatos-Hayward
S. McGill

revenues per bill for 2013 in order to maintain the margin to be earned, Table 4 indicates that, for Shared Bills, the costs are proposed to increase by .094 cents per Bill, while the fee is proposed to increase by only .041 cents per Bill. Please explain how the margin is being maintained, when the increase in costs Enbridge is seeking to recover per Shared Bill is more then twice the increase in fees per Shared Bill that Enbridge is seeking to recover.

RESPONSE

a) The figure of $0.6052 is correct and its breakdown is as noted in the table below. The first difference between this figure and the amount of $.6524 noted in this question is that the $.6524 figure pertains to 2012 as opposed to 2013. The corresponding figure for 2013 is $0.6624. The second difference is due to the application of the terms of the 2009 Open Bill Settlement Agreement (Exhibit D1, Tab 9, Schedule 1, Appendix 1, page 19, para. C) (iv)), where it was recognized that internal overhead costs related to billing services already being notionally recovered in rates would not be considered in the determination of revenues for sharing purposes under the settlement agreement. As such the cost categories "EGD Support Cost", "Allocated IT" and "Postage" are not included in the 2013 total unit cost per shared bill of $0.6052.

Cost components of Shared Bills	**Cost per shared bill**
Customer Care Cost	$0.0626
CIS Functional	$0.0082
CIS IT	$0.0082
OBA Service Enhancement	$0.0062
ABSU	$0.5200
Total	***$0.6052***

b) The determination of the annual margin for this service must consider the number of Shared and Standalone bills for the year including third party charges in addition to the unit costs and revenue rates associated with these services. Unit rates for both Shared and Standalone bills for 2013 were set so as to, at a minimum, maintain the base level of ratepayer benefit generated by the program and maintain a comparable contribution margin for the Company from the provision of in-franchise third party billing services.

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #5

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 7 paragraph 17

The Bill Insert program however, has been less successful. Bill Insert revenues have declined in recent years. Some of the major reasons for this decline have been practical constraints on print inserter capacity and the requirement to accommodate very small geographically targeted volumes of inserts.

a) Please provide a table that sets out, for each of the years 2007 to 2013 on an actual or forecast basis as appropriate, each instance of a 3rd party utilizing the Bill Insert Service, including the number of Bill Inserts distributed in each instance. Please provide the table in a manner that indicates how many uses each particular 3rd party made of the Bill Insert Service over the time period and within each year. By way of example, if a particular third party accessed the Bill Insert Service 8 times over the period of 2007 to 2013, with 4 uses in 2009 with a distribution of 1.4 million each time and 4 uses in 2011 with a distribution of 700,000 each time, the table should be presented in such a way as to provide that information. Please note that we are not interested at this time in the identity of the Bill Insert users, such that for the purposes of this interrogatory it is sufficient to simply distinguish one user from another using numbers, i.e. User 1, User 2, or some other nomenclature.

RESPONSE

Please see Table 1 attached.

Witnesses: K. Lakatos-Hayward
S. McGill

Bill Insert Program
Exhibit 1, Issue D11, Schedule 20.5
Table 1

Bill Insert Program	2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Forecast		2013 Forecast	
	# of Bill Inserts Distributed	# of Instances	# of Bill Inserts Distributed	# of Instances	# of Bill Inserts Distributed	# of Instances	# of Bill Inserts Distributed	# of Instances	# of Bill Inserts Distributed	# of Instances	# of Bill Inserts Distributed	# of Instances	# of Bill Inserts Distributed	# of Instances
3rd Party User 1	1,096,160	2												
3rd Party User 2	8,000,000	7	3,507,260	2	5,483,503	3	1,832,469	1	1,900,000	1	1,900,000	1	1,900,000	1
3rd Party User 3	2,085,200	3												
3rd Party User 4	787,700	1												
3rd Party User 5	231,600	1	560,380	2	624,750	2								
3rd Party User 6	40,940	1	310,600	2	317,340	1								
3rd Party User 7	1,111,920	1	3,282,249	2					600,000	2				
3rd Party User 8			111,960	3										
3rd Party User 9			458,980	1										
3rd Party User 10			1,694,100	1										
3rd Party User 11			146,480	1										
3rd Party User 12			183,600	1										
3rd Party User 13					3,604,882	2								
3rd Party User 14					77,390	1								
3rd Party User 15					2,868	1								
3rd Party User 16							54,916	1						
3rd Party User 17							34,474	2						
3rd Party User 18							1,205,386	5						
3rd Party User 19							305,260	2	185,895	1				
3rd Party User 20							1,336,893	1						
3rd Party User 21							88,553	3						
3rd Party User 22							26,754	1						
3rd Party User 23							222,709	2						
3rd Party User 24									480,224	1				

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D11
Schedule 20.5
Attachment

VECC INTERROGATORY #6

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 15 paragraph 32
Exhibit D1 Tab 9 Schedule 1 Page 22 paragraph 52

The Company proposes that this change in the costs and fees of the Open Bill Services take effect from January 1, 2013 and that the programs continue to operate as is, subject to ongoing enhancement activities to at least the end of 2013.

The Company does not seek any further changes to Open Bill fees for 2013 beyond those described in its original evidence in this proceeding, D1, Tab 9, Schedule 1. However, the Company continues to examine the financial performance of the program and expects that it will bring forward a revised pricing proposal for 2014 designed to improve the financial performance of the program for the Company and increase the likelihood of improved program benefits for ratepayers.

a) The evidence suggests that Enbridge may apply for changes to the program, particularly referencing a revised pricing proposal for 2014, but does not assert specifically that Enbridge will do so. What is Enbridge's proposal in the event it does not file for approval of a proposal for the period beyond 2013, i.e. in the absence of any such proposal is the approval sought from the Board in this application intended to subsist, and if so for how long and with what changes, automatic or otherwise, over time?

RESPONSE

a) With respect to the period beyond 2013 the Company will bring forward a further proposal concerning the open bill program. This may be in the form of a standalone application or may constitute part of the Company's rate application for rates to be effective for 2014 and possibly beyond. For further information please the Company's responses Board Staff Interrogatories # 1 and #12 found at Exhibit I, Issue D11, Schedules 1.1 and 1.12 as well as the response to VECC Interrogatory #13 found at Exhibit I, Issue D11, Schedules 11.13.

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #7

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 17 paragraph 39

Additionally, the Company has had several experiences where Billers have not made significant use of the open bill service subsequent to entering into an OBA Service Agreements. Under these circumstances the Company incurs a degree of expense to put the agreement with the Biller in place and set-up for the acceptance and processing of the Biller's charges in the Company's Customer Information System. To address this issue the Company will institute a "Pre-Payment Amount". The Pre-Payment Amount will be a pre-payment of billing fees. Once the billing service commences the Biller's regular billing fees will be paid by an off-set by the Company against the Pre-Payment Amount until the Pre-Payment Amount has been reduced to zero.

a) What is the quantum of the pre-payment amount and how is it calculated? If applicable please distinguish between any fixed portion of the pre-payment amount that every Biller, regardless of their proposed volume of bills, will be charged, and any portion of the pre-payment amount that is to be calculated on a variable basis.

RESPONSE

a) The prepayment amount will be a flow through of the costs associated with setting up a new billing services client in the Company's customer information system so as to allow them to begin to have their charges presented on the Enbridge bill. The prepayment amount will be $7,500. The Company does not propose to determine the prepayment amount on a variable basis.

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #8

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Page 3 paragraph 7

In its Order dated December 2, 2009, the Board accepted the EB-2006-0043 Open Bill Access Settlement Proposal and the establishment of the deferral and variance accounts necessary to implement Enbridge's proposal.

a) Please confirm that under the current proposal only two deferral and variance accounts, the Open Bill Revenue Variance Account and the Ex-Franchise Third Party Billing Services Deferral Account both as described in Exhibit D1 Tab 8 Schedule 1 pages 16 and 17 are being requested. If other accounts are being requested in connection with Open Bill Access please provide details.

b) With respect to the Open Bill Revenue Variance Account, please confirm that Enbridge's proposal is to maintain a revenue offset in rates related to Open Bill Access of $5.389 million, and that the proposed account will only record debits against ratepayers if the net revenue from Open Bill access (including net revenue from the Bill Insert Service) falls below $4.889 million, and will only record credits to the benefit of ratepayers if the net revenue from Open Bill access (including net revenue from the Bill Insert Service) exceeds $7.389 million.

c) With respect to the proposed Ex-Franchise Third Party Billing Services Deferral Account, please confirm that in determining the net revenue to be recorded in the account the only costs deducted from the gross revenue are incremental costs, and that is the case because no existing Enbridge assets are used to deliver Ex-Franchise Third Party Billing Services. If existing Enbridge assets are used to deliver Ex-Franchise Third Party Billing Services, please describe how those costs are fully allocated to the service; if the costs exist but are not fully allocated to the service, please explain why that is the case.

Witnesses: K. Lakatos-Hayward
S. McGill

RESPONSE

a) Yes, the Open Bill Revenue Variance Account and the Ex-Franchise Third Party Billing Services Deferral Account are the only accounts being requested for 2013. No new deferral or variance accounts are being requested with respect to the open bill program in this application.

b) Yes, EGD confirms that the Open Bill Revenue Variance Account is used to maintain a revenue offset in rates related to Open Bill Access of $5.389 million. The proposed account will only record debits against ratepayers if the net revenue from Open Bill Access (including net revenue from the Bill Insert Service) falls below $4.889 million or credit amounts to the benefit of ratepayers will be recorded in the account if the net revenue from Open Bill Access (including net revenue from the Bill Insert Service) exceeds $7.389 million.

c) With respect to the Ex-Franchise Third Party Billing Services Deferral account, direct costs consisting of Enbridge's service provider costs plus $3,900 per month of internal costs are used in the determination of the net revenue for this program. No CIS costs are allocated to this account as per the October 15, 2009 Open Bill Settlement Agreement (EB-2009-0043, Exhibit N1, Tab 15, Schedule 1, page 14, paragraph c) subparagraph x). Please note that the Company does not expect to have any ex-franchise billing clients utilizing this service in 2013.

Witnesses: K. Lakatos-Hayward
S. McGill

VECC INTERROGATORY #9

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Appendix 3 pages 11 and 12

a) With respect to the 4 tables on these 2 pages, please expand the tables to include the years 2007-2011.

RESPONSE

a) The four tables set out on pages 11 and 12 of Exhibit D1, Schedule 1, Appendix 3 have been revised to include the allocated and incremental actual costs in the same categories identified in the 2011 Open Bill Cost Study, Exhibit D1, Schedule 1, Appendix 3. Incremental ABSU (Accenture) costs are reported as they were incurred. The amounts set out in the other cost categories have been prorated based on the findings of the 2011 Open Bill Cost Study prepared on behalf of Enbridge by InQvis. Note that the "Apr-Dec 12" Column is as presented in the 2011 Open Bill Cost Study and does not include 2012 actual data. Also, the 2011 Open Bill Cost Study begins with the April to December 2012 so as to pick up from where the 2008 cost study's cost projections left off, which was consistent with the April 1 to March 31 contract years provided for in the open bill contracts that were in effect at the time the 2008 Open Bill Cost Study was prepared.

Witnesses: K. Lakatos-Hayward
S. McGill

Total cost per year - Shared

Cost item	Cost type	2007	2008	2009	2010	2011	Apr - Dec '12	2013	2014	2015	2016	2017	2018
Customer Care	Incremental	$80,995	$182,692	$90,559	$253,469	$251,439	$758,689	$1,099,113	$1,189,738	$1,283,549	$1,380,636	$1,481,094	$1,585,019
CIS Functional	Allocated	$11,321	$25,537	$12,658	$35,430	$35,146	$106,049	$144,227	$147,112	$150,055	$153,056	$156,118	$159,241
CIS IT	Allocated	$11,321	$25,537	$12,658	$35,430	$35,146	$106,049	$144,227	$147,112	$150,055	$153,056	$156,118	$159,241
OBA Service Enhancements	Incremental	$8,597	$19,391	$9,612	$26,903	$26,688	$80,527	$109,517	$111,708	$113,942	$116,221	$118,546	$120,918
EGD Support Cost	Allocated	$3,166	$7,140	$3,539	$9,906	$9,827	$29,652	$42,737	$46,035	$49,432	$52,927	$56,520	$60,210
Allocated IT	Allocated	$1,966	$4,434	$2,198	$6,151	$6,102	$18,412	$25,382	$26,225	$27,078	$27,941	$28,815	$29,698
Postage	Allocated	$73,358	$165,467	$82,021	$229,571	$227,733	$687,158	$934,669	$953,498	$972,706	$992,302	$1,012,292	$1,032,685
ABSU	Incremental	$6,982,614	$7,273,642	$7,561,666	$7,936,621	$8,425,001	$6,801,816	$9,128,309	$9,012,563	$9,072,378	$9,322,464	$9,616,532	$10,613,360
Total		**$7,173,338**	**$7,703,839**	**$7,774,911**	**$8,533,481**	**$9,017,082**	**$8,588,352**	**$11,628,180**	**$11,633,991**	**$11,819,194**	**$12,198,604**	**$12,626,034**	**$13,760,372**

Cost per bill - Shared

Cost item	Cost type	2007	2008	2009	2010	2011	Apr - Dec '12	2013	2014	2015	2016	2017	2018
Customer Care	Incremental	$0.0051	$0.0113	$0.0056	$0.0150	$0.0149	$0.0576	$0.0626	$0.0678	$0.0731	$0.0786	$0.0843	$0.0902
CIS Functional	Allocated	$0.0007	$0.0016	$0.0008	$0.0021	$0.0021	$0.0081	$0.0082	$0.0084	$0.0085	$0.0087	$0.0089	$0.0091
CIS IT	Allocated	$0.0007	$0.0016	$0.0008	$0.0021	$0.0021	$0.0081	$0.0082	$0.0084	$0.0085	$0.0087	$0.0089	$0.0091
OBA Service Enhancements	Incremental	$0.0005	$0.0012	$0.0006	$0.0016	$0.0016	$0.0061	$0.0062	$0.0064	$0.0065	$0.0066	$0.0067	$0.0069
EGD Support Cost	Allocated	$0.0002	$0.0004	$0.0002	$0.0006	$0.0006	$0.0023	$0.0024	$0.0026	$0.0028	$0.0030	$0.0032	$0.0034
Allocated IT	Allocated	$0.0001	$0.0003	$0.0001	$0.0004	$0.0004	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016	$0.0016	$0.0017
Postage	Allocated	$0.0046	$0.0103	$0.0050	$0.0136	$0.0135	$0.0522	$0.0532	$0.0543	$0.0554	$0.0565	$0.0576	$0.0588
ABSU	Incremental	$0.4393	$0.4512	$0.4634	$0.4699	$0.4977	$0.5167	$0.5200	$0.5133	$0.5167	$0.5308	$0.5475	$0.6042
Total		**$0.4513**	**$0.4779**	**$0.4765**	**$0.5052**	**$0.5327**	**$0.6524**	**$0.6624**	**$0.6626**	**$0.6731**	**$0.6946**	**$0.7188**	**$0.7833**

Witnesses: K. Lakatos-Hayward
S. McGill

Cost per bill - Stand Alone

Cost item	Cost type	2007	2008	2009	2010	2011	Apr -Dec '12	2013	2014	2015	2016	2017	2018
Customer Care	Incremental	$0.0083	$0.0184	$0.0092	$0.0263	$0.0262	$0.0576	$0.0626	$0.0678	$0.0731	$0.0786	$0.0843	$0.0902
CIS Functional	Allocated	$0.0012	$0.0026	$0.0013	$0.0037	$0.0037	$0.0081	$0.0082	$0.0084	$0.0085	$0.0087	$0.0089	$0.0091
CIS IT	Allocated	$0.0012	$0.0026	$0.0013	$0.0037	$0.0037	$0.0081	$0.0082	$0.0084	$0.0085	$0.0087	$0.0089	$0.0091
OBA Service Enhancements	Incremental	$0.0009	$0.0020	$0.0010	$0.0028	$0.0028	$0.0061	$0.0062	$0.0064	$0.0065	$0.0066	$0.0067	$0.0069
EGD Support Cost	Allocated	$0.0003	$0.0007	$0.0004	$0.0010	$0.0010	$0.0023	$0.0024	$0.0026	$0.0028	$0.0030	$0.0032	$0.0034
Allocated IT	Allocated	$0.0002	$0.0004	$0.0002	$0.0006	$0.0006	$0.0014	$0.0014	$0.0015	$0.0015	$0.0016	$0.0016	$0.0017
Postage	Incremental	$0.5000	$0.4989	$0.5088	$0.5822	$0.5769	$0.5800	$0.6000	$0.6300	$0.6600	$0.6900	$0.7200	$0.7500
ABSU	Incremental	$0.4393	$0.4492	$0.7688	$0.7991	$0.8306	$0.8167	$0.8200	$0.8200	$0.8325	$0.8558	$0.8825	$0.9533
Total		**$0.9513**	**$0.9748**	**$1.2909**	**$1.4195**	**$1.4456**	**$1.4802**	**$1.5092**	**$1.5450**	**$1.5935**	**$1.6531**	**$1.7162**	**$1.8237**

Total cost per year - Stand alone

Cost item	Cost type	2007	2008	2009	2010	2011	Apr -Dec '12	2013	2014	2015	2016	2017	2018
Customer Care	Incremental	$4,230	$11,442	$5,252	$12,628	$12,166	$18,590	$26,928	$29,144	$31,438	$33,811	$36,266	$38,805
CIS Functional	Allocated	$591	$1,599	$734	$1,765	$1,701	$2,599	$3,534	$3,604	$3,675	$3,748	$3,823	$3,899
CIS IT	Allocated	$591	$1,599	$734	$1,765	$1,701	$2,599	$3,534	$3,604	$3,675	$3,748	$3,823	$3,899
OBA Service Enhancements	Incremental	$449	$1,214	$557	$1,340	$1,291	$1,973	$2,683	$2,736	$2,791	$2,846	$2,903	$2,960
EGD Support Cost	Allocated	$165	$447	$205	$494	$475	$727	$1,047	$1,128	$1,211	$1,296	$1,384	$1,474
Allocated IT	Allocated	$103	$278	$127	$306	$295	$451	$622	$642	$663	$684	$706	$727
Postage	Allocated	$255,368	$309,984	$291,579	$279,170	$267,543	$187,084	$258,047	$270,950	$283,852	$296,755	$309,657	$322,559
ABSU	Incremental	$224,383	$279,066	$440,610	$383,162	$385,201	$263,423	$352,665	$352,665	$358,041	$368,076	$379,545	$410,009
Total		**$485,879**	**$605,631**	**$739,798**	**$680,631**	**$670,373**	**$477,446**	**$649,059**	**$664,473**	**$685,346**	**$710,964**	**$738,105**	**$784,331**

VECC INTERROGATORY #10

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Appendix 3 page 16 paragraph 34

Subsequent to the Company's submission of its initial Open Bill evidence for the 2013 Test Year, EGD determined that a number of changes to the Open Bill Access Billing and Collection Services Agreement as filed with the Board in EB-2009-0043 (the "OBA Agreement") are required in order to support the continued viability of the program. Although some of these changes are administrative in nature, the more significant of them are in response to a number of recent and significant customer related incidents, which for the most part stem from the nature of the sales activities undertaken by some Open Bill Access clients ("Billers") and which are negatively impacting the Company.

a) Please provide details as to the nature of the incidents referred to in this paragraph. Please note that the identities of Billers or customers are not requested through this interrogatory.

RESPONSE

a) The majority of the customer related incidents referred to in the Company's evidence are associated with the Door-to-Door sales tactics employed by a number of the Company's open bill service clients. The key issues experienced are:

- Sales representatives of open bill services clients misrepresenting themselves as representatives of Enbridge, government agencies or the customer's incumbent service provider.
- Sales representatives of open bill services clients misrepresenting themselves as representatives of Enbridge, or the customer's incumbent service provider tasked to inspect the customer's hot water heater.
- Sales representatives misrepresenting Carbon Offsets or Carbon Credits as a product or service that will lead to a reduction in the customer's natural gas or

gas distribution charges if customer enters into a Carbon Offset contract with the company they represent.

- Door to door sales representatives not providing customers with copies of their contracts which is not compliance with the requirements of the Ontario Consumer Protection Act.
- Sales representatives collecting customer information through various means, such as a survey.
- Sale representatives creating forged contracts to enter the customer into a contract for a product / service where charges are to be invoiced on the Enbridge bill.
- Sales representatives providing customer information obtained while representing one billing client to sales representative of another billing client for the purpose of creating forged customer contracts.
- Sales representatives harassing, intimidating or threatening customers.
- Certain billing service clients have implemented policies and practices that make it very difficult and cumbersome for customers to return water heaters when changing rental water heater service providers, often resulting in customers being charged rental fees for both their new and former (removed) water heater on their Enbridge bill at the same time.

VECC INTERROGATORY #11

INTERROGATORY

D - Operating Costs
Issue 11: Is the proposal for the Open Bill Access Program appropriate?

Reference: Exhibit D1 Tab 9 Schedule 1 Appendix 3 page 17 paragraph 38

Section 4.3 has been revised to enable EGD to recover costs incurred to investigate and resolve customer disputes and potential breaches of the Open Bill Service Agreement by Billers. The need for this facility is to allow the Company to recover the cost of these activities from those that bring about the need for such actions as opposed to including these costs in the overall Billing Fee. Such costs will be defined as corrective costs and include, but are not limited to outside legal advice, auditors, consultants and investigators engaged by the Company to investigate or follow-up on such breaches or potential breaches of the agreement.

a) Please confirm that the costs Enbridge seeks to recover through this proposed change are to be recovered directly from Billers, and that the proposed change does not impact on ratepayers in any way.

RESPONSE

Yes, the Company intends to recover corrective costs from the billing service client under investigation. This change is not expected to have any economic impact on ratepayers and should benefit customers to the extent this aspect of the open bill program improves the overall quality of the Open Bill program.

Witnesses: K. Lakatos-Hayward
S. McGill

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 12: Is the proposed O&M budget for Finance appropriate?

Ref: D1/T10/S1/p. 1

Within the Finance Budget there are $329,000 in expenses related to Travel and Entertainment and $327,000 related to "memberships, employee services and development, and materials and supplies." Please provide a more detailed explanation for these cost items. What were the actual costs in each year for the period 2007-2011?

RESPONSE

Travel and Entertainment expense is primarily the costs associated with business trips: airfare, ground transportation, accommodation, meals and entertainment, and conference and registration fees.

The business trips in Finance include professional and industry conferences, inter-office meetings, audit travels, and training. The increase in 2013 Budget is largely driven by the expectation of an increased level of business travel in various Finance functions.

Other expenses are primarily comprised of professional membership fees and employee training and development costs. The membership fees for professional accounting designations (CA, CGA, and CMA) are expected to rise from year to year. Also, there is an emphasis on enhancing the business acumen of Finance professionals through training.

Please refer to the following table for the actual costs in each year for the period 2007 to 2011.

Witnesses: S. Chhelavda
S. Kancharla
R. Lei

Finance Department $ Thousands	Actual 2011	Actual 2010	Actual 2009	Actual 2008	Actual 2007
Travel and Entertainment	201	172	141	163	153
Other Expenses	254	567	355	459	349

Witnesses: S. Chhelavda
S. Kancharla
R. Lei

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 12: Is the proposed O&M budget for Finance appropriate?

Ref: Exhibit D1, Tab 10, Schedule 1

What is the impact on the revenue requirement for 2013 if the salaries and wages reflected an annual salary increase of 2.0% in both 2012 and 2013 in place of the 3.3% proposed for non-union employees?

RESPONSE

The salary increase sensitivity should be addressed at the overall company level rather than at the departmental level because the merit increases are determined by HR and then applied consistently across the Company. Departments adhere to the HR guidelines.

Please refer to the response to Energy Probe Interrogatory #5 at Exhibit I, Issue D1, Schedule 7.5.

Witnesses: J. Jozsa
S. Kancharla
R. Lei

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 12: Is the proposed O&M budget for Finance appropriate?

Ref: D1/10/1, p. 2

Please provide a table of FTEs in Finance, broken down into the three major employee categories, for each of 2007 through 2013.

RESPONSE

Below are the FTEs for Finance, broken down into the three major employee categories from 2007 to 2013. Please note that the actuals from 2007 to 2011 didn't include vacancies. Also, the year over year variances may be masked by reorganizations.

	2007	2008	2009	2010	2011	2012	2013
Management	7.5	10.1	12.0	11.1	10.1	11.7	11.7
Supervisory	45.1	43.0	45.5	47.6	48.4	55.4	56.8
Union	9.7	9.5	9.5	8.4	8.7	8.0	8.0
Total	62.3	62.6	67.0	67.1	67.2	75.1	76.5

Witnesses: S. Chhelvada
S. Kancharla
R. Lei
B. Yuzwa

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 12: Is the proposed O&M budget for Finance appropriate?

Ref: D1/10/1, p. 2

Please provide details on the RCAM budget relating to Finance, including dollars charged and FTEs. Please provide a detailed breakdown and explanation showing the Finance functions that are handled by the Applicant, and the Finance functions that are provided by EI, together with the rationale for the division of responsibilities proposed for the Test Year.

RESPONSE

The RCAM budget relating to Finance, including dollars charged and FTEs are outlined in attachment 1 to this interrogatory.

There are five Finance related services provided by EI to the Company to supplement its Finance function, they are as follows:

Audit and Accounting Advice
Corporate Compliance
Planning, Management & Execution of Internal Audits
Risk Assessment Management
Tax Reporting and Planning

Additionally, there are six services for which the Company does not have its own capability, they are as follows:

Board of Directors Support
Capital Market Financing and Access
Cash Management and Banking
External Audit Coordination
Investor Services
Rate Regulated Entity Support

Witnesses: S. Chhelvada
S. Kancharla
R. Lei
B. Yuzwa

Services requiring sophisticated, specialized professionals where access is needed on a demand basis are typically best served through a shared services model, where economies of scale benefits can be achieved.

For example, being part of a much larger and stronger entity, the Company is able to receive preferential banking terms, competitive audit fees and to media coverage and response.

The Company does not have treasury positions undertaking the activities relating to raising and maintaining equity capital. The treasury function at EI is in the best position to achieve the tightest possible transaction pricing, and the greatest service from investment and commercial banks, as a result of enhanced "buying power" associated with treasury activity in support of a significantly larger asset base. It is able to provide a superior quality of service, both with respect to transaction execution and financial advice as a result of having greater critical mass and therefore greater diversity of skills and experience and greater depth to deal with peak requirements.

Investor Relations is another area that has a direct impact on the accessibility of additional financing in the capital market. The Company benefits from access to a much larger audience of investors through EI's road shows and Enbridge day presentations.

Another rationale is that, while policy development, compliance oversight, advice and guidance are important, they do not need to be supported by fulltime dedicated senior roles. Again, the shared services model, for the various other Finance functions listed above, allows the Company unlimited access to industry's best practices in a cost effective manner.

Witnesses: S. Chhelvada
S. Kancharla
R. Lei
B. Yuzwa

EI SERVICES SUPPORTING EGD's FINANCE FUNCTION:

1. Audit and Accounting Advice (provided on a supplemental basis)
2. Board of Directors Support
3. Capital Market Financing and Access
4. Cash Management and Banking
5. Corporate Compliance (provided on a supplemental basis)
6. External Audit Coordination
7. Investor Services
8. Planning, Management & Execution of Internal Audits (provided on a supplemental basis)
9. Rate Regulated Entity Support
10. Risk Assessment Management (provided on a supplemental basis)
11. Tax Reporting and Planning (provided on a supplemental basis)

DEPARTMENTS SUPPORTING THE ABOVE SERVICES	2013F LOADED DEPT BUDGET*	2013F DEPT RCAM ALLOCATION*	2012 FTE (proxy for 2013)
Audit Services (Calgary) (10050)	$ 2,655,714	$ 140,532	0.5
CEO (10000)	$ 13,239,785	$ 750,254	0.1
CFO (10045)	$ 3,801,345	$ 276,887	0.2
Corporate Controller (10047)	$ 16,289,824	$ 129,391	0.3
Corporate HR (10092)	$ 4,033,779	$ 17,612	0.0
Corporate Secretarial (10070)	$ 4,521,190	$ 108,660	0.2
Enterprise Risk (10046)	$ 11,179,145	$ 628,627	2.1
HR Business Solutions (10089)	$ 2,045,946	$ 2,866	0.0
Investor Relations (10043)	$ 2,477,215	$ 66,660	0.1
People & Partners (10094)	$ 3,983,839	$ 302,723	0.2
Public Affairs & Corp. Comm. (10072)	$ 17,307,836	$ 15,216	0.0
Tax Services (Calgary) (10049)	$ 3,232,318	$ 40,893	0.2
Total Compensation (10091)	$ 3,913,476	$ 77,297	0.2
Treasury (10044)	$ 7,381,693	$ 938,124	2.2
Total		**$ 3,495,742**	**6.4**

*Includes total department cost, but excludes support services, corporate secretarial legal fees, and charges from Enbridge pipelines inc. which equate to $1,537,341 for 2013.

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 12: Is the proposed O&M budget for Finance appropriate?

Ref: D1/10/1, p. 4

Please advise how the three replacement positions filled in 2011 were incremental FTEs if they were replacements.

RESPONSE

When an employee leaves the Company, the position becomes vacant until it is filled by the replacement. Even though the three positions were replaced in 2011, there was a lag period between when these positions became vacant and when they were replaced. Hence these positions were not fully effective in 2011 but fully effective in 2012, resulting as incremental FTEs in 2012.

Witnesses: S. Chhelvada
S. Kancharla
R. Lei
B. Yuzwa

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 13: Has Enbridge properly implemented the revenue requirement associated with the Customer Care and CIS Settlement Agreement (per EB-2011-0226)?

Ref: Ex. D1 /Tab 12/ Sch 1 / para 2

Please provide a summary schedule showing the components of, and how the referenced $11 million revenue deficiency, is derived.

RESPONSE

The $11 million Customer Care/CIS ("CC/CIS") revenue deficiency or approved rate increase is arrived at by comparing the 2013 CC/CIS approved revenue of $110.2 million to the 2012 CC/CIS approved revenue of $99.2 million. A copy of the CC/CIS Board approved Settlement Agreement and specifically the table showing the approved revenue is filed at Exhibit D1, Tab 12, Schedule 2, page 43.

Row 23, Column H of the agreement, shows the 2013 approved revenue of $110.2 million and Row 23, Column F shows the 2012 approved revenue of $99.2 million.

Witnesses: K. Culburt
K. Lakatos-Hayward
S. McGill

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: Ex. D1 /Tab 13/ Sch 1 / para 17 / Table 1

With reference to Table 1, please explain the $2.1 million in costs charged from an affiliate and provide a comparison with the costs of the previous 2 years. Please also explain the $0.9 million credit in costs charged to an affiliate on the same table.

RESPONSE

The charges from an affiliate of $2.1 million in the 2013 Test Year, relate to SCADA, IT, and Facilities services utilized by Enbridge Gas Distribution's Gas Control and Nominations group in Edmonton. The SCADA system is used to safely operate the gas distribution system by monitoring and sending commands to field equipment. Technical support for this system is provided by the SCADA group in Edmonton. IT services are technology support services, including such functions as help desk support, hardware requirement, network management, and technical support for specialized Gas Control and Scheduling computer systems. Facilities services include office rent in Edmonton, office furniture and office supplies. All of these services are provided by Enbridge Pipelines Inc. by way of a service level agreement. The forecast for these costs in 2013 is expected to be $400,000 lower than the filed amount of $2.1 million, or approximately $1.7 million. In comparison, the 2012 Bridge Year forecast for these costs is $1.6 million, while the 2011 actual amount was $1.9 million.

The 2013 Test Year credit of $0.9 million, for costs charged to affiliates, is in recognition of departmental time and resources utilized for affiliate requirements. Services provided to affiliates are in accordance with service level agreements, and are billed on a fully allocated cost basis, or utilizing market based rates. The majority of the credit, $0.8 million, relates to gas control and nomination services provided to EGD affiliates, as well as the unregulated storage business. The remaining $0.1 million relates to regulatory support provided to affiliates. Services include preparation and filing of regulatory applications and compliance documents, revenue requirement determination, rate/toll design, and witnessing. Costs charged to affiliates in prior years relate to similar activities.

Witnesses: K. Culbert
J. Sarnovsky
R. Small

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: Ex. D1 /Tab 13/ Sch 1 / para 22 / Table 2

With reference to Table 2, please provide a breakdown of the components of the Regulatory proceeding costs for the period 2007 to 2013.

RESPONSE

A breakdown of the components of the regulatory proceeding costs from fiscal 2007 through 2013 is provided in the attached table.

Witnesses: K. Culbert
J. Sarnovsky
R. Small

TABLE A

Breakdown of the Components of Regulatory Proceeding Costs
2007 through 2013

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9
		2013 Test	2012 Bridge	2011 Actual	2010 Actual	2009 Actual	2008 Actual	2008 Board Approved	2007 Actual	2007 Board Approved
		($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)	($000's)
1.	Legal	900.0	840.0	208.3	691.9	536.0	975.0	840.0	1,526.0	840.0
2.	Intervenor	900.0	1,155.0	259.6	488.5	361.3	874.0	1,155.0	881.0	1,155.0
3.	Ontario Energy Board	3,250.0	4,040.0	3,098.1	3,363.2	3,960.3	3,851.0	4,040.0	3,661.0	4,140.0
4.	Consultants	1,100.0	500.0	16.7	169.8	275.5	994.0	500.0	872.0	400.0
5.	Transcripts, newspaper notices, printing, other	392.5	420.0	277.8	160.1	182.6	406.6	420.0	403.5	420.0
6.	Sub-total	6,542.5	6,955.0	3,860.5	4,873.5	5,315.7	7,100.6	6,955.0	7,343.5	6,955.0
7.	Other proceedings and consultatives	800.0	1,887.5	950.1	1,054.0	1,000.0	994.0	1,887.5	4,020.0	1,887.5
8.	Total Regulatory Proceeding Costs - Actual	7,342.5	8,842.5	4,810.6	5,927.5	6,315.7	8,094.6	8,842.5	11,363.5	8,842.5
9.	Amount transferred to OHCVA	-	-	(1,031.9)	85.0	473.2	2,252.1	-	2,521.0	-
10.	Agreed to OHCVA threshold reduction		(3,000.0)	-	-	-	-	(3,000.0)	-	-
11.	Regulatory Proceeding Costs	7,342.5	5,842.5	5,842.5	5,842.5	5,842.5	5,842.5	5,842.5	8,842.5	8,842.5
12.	OEB Approved - Regulatory Proceeding Costs		5,842.5	5,842.5	5,842.5	5,842.5	5,842.5	5,842.5	8,842.5	8,842.5
	Breakdown of Other Proceedings (Line 7, Col. 3 - 7 above)									
1.	DSM Input Assumptions / Clearance Application & Consultative			274.5	344.4	69.9	71.0		791.0	
2.	CIS & Open Bill Consultatives			545.3	326.0	128.6	79.8		1,940.0	
3.	Regulatory Cost Alloc Methodology Review ("RCAM")			91.1	112.5	3.9	-		686.0	
4.	Consultation on Energy Issues / Low Income Consumers			39.2	44.6	46.2	117.1		-	
5.	Storage & Transportation Access Rule			-	167.2	3.4	-		-	
6.	Return on Equity - Cost of Capital EB-2009-0084 (intervenor costs)			-	59.3	566.9	30.6		-	
7.	EB-2008-0408 OEB IFRS Consultative			-	-	179.9	0.7		-	
8.	Gas Storage Allocation / other Consultative			-	-	-	-		-	
9.	Incentive Regulation			-	-	-	252.9		-	
10.	NGEIR & Gas Storage Allocation Policy			-	-	-	175.9		445.0	
11.	Aboriginal consultation Policy			-	-	-	9.0		-	
12.	Integrated Power System Plan			-	-	1.2	74.6		-	
13.	CASDA / Garland			-	-	-	159.5		-	
14.	Envision			-	-	-	-		139.0	
15.	OEB Costs - Incentive Regulation				-	-	-		19.0	
16.	Transactional Services						22.9			
17.	Total - Other proceedings			950.1	1,054.0	1,000.0	994.0	-	4,020.0	-

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D14
Schedule 1.2
Attachment

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: D1/T13/S1

The evidence states that the Energy Supply, Storage Development and Regulatory (ESSDR) business unit encompasses four departments - Energy Supply and Policy, Regulatory Affairs, Storage Development and the Greater Toronto Reinforcement Project. Please provide a separate detailed budget for each department for the period 2011, 2012, and 2013.

RESPONSE

The breakdown of ESSDR business unit costs can be found in the table below. 2011 historical information has been updated to reflect actual results.

As stated in Exhibit D1, Tab 13, Schedule 1, Storage Development responsibilities within this business unit are in relation to the development of unregulated storage. The associated costs are contained within a separate unregulated line of business and are not resident within utility regulated budget or actual financial costs or results.

The majority of costs associated with the Greater Toronto Area Reinforcement Project are capitalized and included within the capital budget, and therefore not resident within the O&M budget.

Witnesses: K.Culbert
S. Kancharla
R. Lei
R. Small

ENERGY SUPPLY, STORAGE DEVELOPMENT, AND REGULATORY AFFAIRS (ESSDR)

ESSDR Management	2013 Test ($000's)	2012 Bridge ($000's)	2011 Actual ($000's)
Salaries and wages	762.5	738.2	518.1
Consulting	91.6	90.0	-
Training, travel, and other business expenses	103.3	109.2	34.7
Regulatory proceeding costs	-	-	-
Costs charged from an affiliate	-	-	-
Costs charged to an affiliate	-	-	-
Other	37.6	36.6	2.6
	$ 995.0	$ 974.0	$ 555.4

Energy Supply & Policy	2013 Test ($000's)	2012 Bridge ($000's)	2011 Actual ($000's)
Salaries and wages	3,103.9	3,010.4	2,805.7
Consulting	55.0	55.0	52.2
Training, travel, and other business expenses	199.4	195.8	158.4
Regulatory proceeding costs	-	-	-
Costs charged from an affiliate	2,088.4	1,588.9	1,894.2
Costs charged to an affiliate	(807.5)	(787.6)	(763.0)
Other	137.7	137.7	98.3
	$ 4,776.9	$ 4,200.2	$ 4,245.8

Regulatory Affairs	2013 Test ($000's)	2012 Bridge ($000's)	2011 Actual ($000's)
Salaries and wages	2,135.8	2,176.8	1,924.9
Consulting	155.0	150.0	151.8
Legal	-	-	11.2
Training, travel, and other business expenses	88.3	86.7	48.8
Regulatory proceeding costs	7,342.5	5,842.5	4,819.2
Upstream regulatory costs - legal	-	-	-
- consulting	125.0	125.0	47.1
- other	86.8	86.4	1.7
Costs charged from an affiliate	-	-	-
Costs charged to an affiliate	(54.0)	(53.0)	(79.1)
Other	37.1	36.1	30.6
	$ 9,916.5	$ 8,450.5	$ 6,956.2
Total ESSDR	$ 15,688.4	$ 13,624.7	$ 11,757.4

Witnesses: K.Culbert
S. Kancharla
R. Lei
R. Small

CCC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: D1/T3/S1

With respect to Regulatory Affairs please provide a schedule setting out the following for 2007-2013:

- Salaries and Wages
- Consulting
- Training, Travel and other Business expenses
- 2013 Rate Case Costs (broken out by legal, intervenor, consulting, and other)
- NEB proceedings costs (broken out by legal, consulting and other)
- Other Regulatory Proceedings Costs
- Other Costs

RESPONSE

The schedule on the following page provides Regulatory Affairs costs for 2007 through 2013.

The details of Regulatory Proceeding costs are provided in Board Staff Interrogatory #2 at Exhibit I, Issue D14, Schedule 1.2.

Witnesses: S. Kancharla
K. Culbert
R. Lei
R. Small

Regulatory Affairs		2013 Test ($000's)	2012 Bridge ($000's)	2011 Actual ($000's)	2010 Actual ($000's)	2009 Actual ($000's)	2008 Actual ($000's)	2007 Actual ($000's)
Salaries and wages		2,135.8	2,176.8	1,924.9	1,828.5	1,609.5	1,916.7	1,731.7
Consulting		155.0	150.0	151.8	212.8	235.7	371.8	47.6
Legal		-	-	11.2	123.2	10.4	32.1	149.9
Training, travel, and other business exp.		88.3	86.7	48.8	62.5	20.6	59.1	68.8
Regulatory proceeding costs		7,342.5	5,842.5	4,819.2	5,842.5	5,842.5	5,842.5	8,842.5
Upstream regulatory costs	- legal	-	-	-	-	-	-	99.6
	- consulting	125.0	125.0	47.1	-	-	-	15.0
	- other	86.8	86.4	1.7	12.1	16.5	21.2	15.7
Costs charged from an affiliate		-	-	-	-	-	-	-
Costs charged to an affiliate		(54.0)	(53.0)	(79.1)	(79.8)	(90.8)	(98.2)	(56.8)
Other		37.1	36.1	30.6	69.0	32.7	28.7	29.9
		$ 9,916.5	$ 8,450.5	$ 6,956.2	$ 8,070.8	$ 7,677.1	$ 8,173.9	$10,943.9

Witnesses: S. Kancharla
K. Culbert
R. Lei
R. Small

CCC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: D1/T3/S1

Within the ESSDR Budget there is an amount entitled "Costs Charged From an Affiliate" of $2.088 million. Please explain the nature of that charge.

RESPONSE

Please see the response to Board Staff Interrogatory #1 at, Exhibit I, Issue D14, Schedule 1.1.

Witnesses: K. Culbert
J. Sarnovsky
R. Small

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Revenue
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: Exhibit D1, Tab 13, Schedule 1

a) Please confirm that the $400,000 reduction from the 2013 budget noted in paragraph 21 has not been reflected in either Table 2 or the calculation of the overall revenue requirement for the test year. If this cannot be confirmed, please indicate where this reduction has been reflected in the revenue requirement.

b) Please provide an update on the status of negotiations noted in paragraph 21 and, if necessary, please update the figure of $400,000.

RESPONSE

a) Table 2 and the calculation of the overall revenue requirement for the Test Year do not reflect the $400,000 reduction from 2013 budget noted in Paragraph 21.

b) The Service Level Agreements have not been finalized so there is no change to the expected savings at this time.

Witnesses: K. Culbert
J. Sarnovsky
R. Small

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Ref: D1/13/1, p. 8, 9

Please explain the increase of $499,000 in costs charged from an affiliate from 2012 to 2013. Please confirm that this estimate is expected to be reduced by $400,000.

RESPONSE

As indicated in Exhibit D1, Tab 13, Schedule 1, Paragraph 21, the increase in costs charged from an affiliate from 2012 to 2013 of $499,000 was due to the fact that the scope of services under the service level agreement for the provision of SCADA, IT and Facilities services for 2013 had not been fully defined or negotiated. While Service Level Agreements have not been finalized, the Company confirms the forecast for these costs in 2013 is expected to be $400,000 lower than the filed amount of $2.1 million.

Witnesses: K. Culbert
J. Sarnovsky
R. Small

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 14: Is the proposed O&M budget for Energy Supply, Storage Development and Regulatory appropriate?

Reference: Exhibit D2 Tab 5 S1 B&V Storage Cost Allocation Study Page 25 Tables 3, 4

a) Provide a copy of the above Tables with 2012 E and 2013 F Costs before and after the proposed chamges recommended by B&V.

b) Show how the cost changes have been carried through into the 2011A, 2012E and 2013 O&M budgets for Storage Operations.

RESPONSE

Please see the response to FRPO Interrogatory #12 at Exhibit I, Issue B6, Schedule 8.12.

Witness: R. Feingold, Black & Veatch
J. Sanders
B. Pilon

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 15: Is the proposed O&M budget for Law appropriate?

Ref: Ex. D1 /Tab 14/ Sch 1 / para 12 / Table 1

With reference to Table 1 and the line "External Legal Costs", is there a tender process for the $3.5 million in external legal costs?

RESPONSE

EGD does not in the normal course have a formal tender process for externally sourced legal services. For allocating certain larger, discrete project-specific packages of legal work, EGD will solicit proposals from law firms to inform its selection of a service provider. Much of the balance of EGD's external legal work involves a higher volume of lower value matters that often share similar characteristics or interrelated issues. For these matters, separate formal tender processes would not be feasible or in the best interest of EGD.

In the normal course, EGD allocates most of its legal work using a mix of value-based factors including firm expertise, knowledge of and experience with EGD's business, avoidance of conflicts, and negotiated discount arrangements. Discounts from normal billable rates are negotiated with key service providers either locally or on an enterprise-wide basis.

Witness: L. Cornwall

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 15: Is the proposed O&M budget for Law appropriate?

Ref: D1/T14/S1/p. 6

Please provide a detailed break-down of the $3.5 million in External Legal Costs. Pease provide actual number for the years 2007-2011, and the forecast for 2012.

RESPONSE

As described on page 2 of the referenced evidence, $3.5 million represents the 2013 budget for the majority of EGD's external legal costs that were previously budgeted as part of the operations and maintenance budget of other EGD departments (e.g., Operations, Customer Care, Damage Prevention/Risk, Facilities, Finance, etc.). External legal costs recorded in capital project accounts, the Ontario Hearing Cost Variance Account and the Manufactured Gas Plant Deferral Account are not part of the Law Department's $3.5 million budget. A summary of EGD's actual external legal spend for the years 2007 to 2011, subject to a small number of legal invoices that may not have been reviewed by the Law Department is:

Year	2007	2008	2009	2010	2011
Total EGD External Legal Spend	$6,395,630	$4,492,052	$3,668,113	$4,262,638	$3,944,139

As noted on page 7 of the evidence, EGD is forecasting an amount of $3.495 million for external legal costs in 2012, excluding legal costs captured in other accounts, as noted above.

Witness: L. Cornwall

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 15: Is the proposed O&M budget for Law appropriate?

Ref: D1/14/1, p. 2

Please quantify the forecast savings to the Applicant in the Test Year as a result of the two retainer agreements referred to, and show the supporting calculations.

RESPONSE

2013 costs are budgeted relative to historical expenditures, workload, and other forward-looking factors, and not specifically for savings attributable to specific retainer agreements. As noted in response to CCC #1, found at Exhibit I, Issue D15, Schedule 5.1, EGD's external legal spend varies greatly, depending upon what legal matters arise from year to year. Similarly, fees paid to each law firm vary greatly from year to year. It is therefore difficult to provide an accurate estimate of future savings that may be attributable to specific retainer agreements, even based upon historical data.

EGD has nonetheless attempted to calculate a possible range of savings of $100,000 to $300,000 that may be attributable to the noted retainer agreements based upon an historical average of fees paid over the last five years. EGD cannot provide any more detailed calculations without disclosing commercially sensitive information proprietary to the subject firms.

Witness: L. Cornwall

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 15: Is the proposed O&M budget for Law appropriate?

Ref: D1/14/1, p. 3

Please identify in the Application the savings in amounts paid for external legal services as a result of the two new in-house lawyers referred to in para. 6.

RESPONSE

The Application requests approval of budgeted costs for 2013 for which no expenditures for external legal services have yet been made. EGD budgets for costs relative to historical expenditures, workload, and other forward-looking factors, and not specifically for savings attributable to each lawyer. Nevertheless, based upon internal time records and an estimate of EGD's fully allocated costs relative to avoided external legal costs, EGD estimate potential savings for 2013 attributable for the two lawyers referenced (the first hired in 2008, and the second to be hired later in 2012) to be approximately $150,000 to $300,000.

Witness: L. Cornwall

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 15: Is the proposed O&M budget for Law appropriate?

Ref: D1/14/1, p. 4

Please explain why two new positions are required for Records Management. Please provide details of any IT solutions that are being used for this function. Please provide details of any changes in policies or procedures that have driven the need to add more positions. Please identify all RCAM amounts being charged to the Applicant relating to Records Management.

RESPONSE

The need for a more robust and comprehensive records and information management program is a direct result of the increasingly complex and burdensome governance and compliance environment in which EGD operates. There are also increased requirements for Records Management governance including chain of custody requirements and auditable, verifiable and traceable critical records to meet current business governance and control best practices.

The two new positions in Records Management are responsible for executing records and information management initiatives. The Records Management staff will ensure the implementation of Records Management best practices and risk avoidance as it relates to Records Management within EGD. The IT system used by EGD for documents and records is the Livelink Enterprise Content Management System, for which Records Management staff provide expert user support.

The Records Management program governance (strategy, design, development and oversight) is provided by Enbridge Inc. as part of the enterprise-wide Records and Information Management Service. The evidence referenced represents the direct internal EGD costs incurred by the Law Department for Records Management. The cost for the provision of Records Management services has been identified in the MNP Report at Exhibit D2, Tab 1, Schedule 1, Appendix A, pages 198 to 200. Costs for Records Management services at EGD coupled with the allocation of costs related to the provisions of Records Management services by EI (ie RCAM allocation related to

Records and Information Management) represent the appropriate budget for EGD's Records Management needs.

Witnesses: L. Cornwall
D. Martin

SEC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 15: Is the proposed O&M budget for Law appropriate?

Ref: D1/14/1, p. 7

Please provide details on the RCAM budget relating to the Law Department, including dollars charged and FTEs. Please provide a detailed breakdown and explanation showing the Law Department functions that are handled by the Applicant, and the Law Department functions that are provided by EI, together with the rationale for the division of responsibilities proposed for the Test Year.

RESPONSE

FTE equivalents for RCAM allocations to the Law Department are outlined in Attachment 1 to this interrogatory.

There are two services provided by EI to EGD to supplement EGD's Law function, namely Legal Advice and Records & Information Management. Information about the Records & Information Management service is provided in the response to SEC Interrogatory #4 at Exhibit I, Issue D15, Schedule 14.3.

The Legal Advice service is provided by Corporate Law and the Corporate Secretarial Departments. Through this service, EGD gains access to additional legal precedents, research material and legal experts who provide advice related to various EGD initiatives including contracts, litigation, and regulatory proceedings that EGD lawyers are working on directly. Examples of EI activities related to this service are:

- monitoring changes in federal legislation and identifying suggested changes to corporate policies, and assisting with drafting of such policies;
- developing and maintaining an enterprise-wide legal precedents database; and
- coordinating and managing the selection process for certain external law firms retained by EGD.

The Corporate Secretarial Department supports this service by providing legal expertise, paralegal and administrative services to the EGD Board of Directors and

Audit, Finance and Risk Committee that supplement the corporate secretarial functions that EGD lawyers fulfill. Examples of these EI activities are:

- legal advice in support of EGD financing matters;
- press release and other publication review related to the activities of EGD's Board; and
- advice to the EGD Disclosure Committee and with respect to EGD's continuous disclosure obligations under applicable securities laws.

EI SERVICES SUPPORTING EGD's LAW FUNCTION:

1. Legal Advice (provided on a supplemental basis)
2. Records and Information Management (provided on a supplemental basis)

DEPARTMENTS SUPPORTING THE ABOVE SERVICES	2013F LOADED DEPT BUDGET*	2013F DEPT RCAM ALLOCATION*	2012 FTE (proxy for 2013)
Corporate Secretarial (10070)	$ 4,521,190	$ 32,455	0.1
Corporate Law (10077)	$ 6,110,612	$ 287,522	0.9
Enterprise Content Management (10075)	$ 5,949,877	$ 310,981	0.6
Executive VP Corporate Law (10078)	$ 3,848,446	$ 115,453	0.1
Total		**$ 746,411**	**1.7**

*Includes total departmental costs, but excludes expense items such as support services, licence and consulting fees, and charges from Enbridge Pipelines Inc. which equate to $329,384 for 2013

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 16: Is the proposed O&M budget for Operations appropriate?

Ref: Ex. D1 /Tab 15/ Sch 1 / para 25 / Table 3

With reference to Table 3, please provide a 5 year table for Operations, showing the actual spend, in a similar level of detail to Table 3.

RESPONSE

Response to Board Staff Interrogatory # 1
Enbridge Gas Distribution Inc.
Operations, 2007-2011 Actual

Line No.	Particulars ($000's)	2011 Actual	2010 Actual	2009 Actual	2008 Actual	2007 Actual
1	Salaries and Wages	78,172	75,214	71,428	74,304	77,664
2	Capitalization	(45,652)	(44,128)	(42,457)	(44,549)	(47,263)
3	Net Salaries and Wages	32,519	31,086	28,971	29,756	30,401
4	Materials and Supplies	2,994	3,001	2,539	4,341	2,457
5	Outside Services	25,093	23,761	22,073	19,934	19,483
6	Consulting	998	1,387	1,278	918	359
7	Repairs and Maintenance	1,221	1,467	1,661	351	2,485
8	Fleet	8,496	7,705	7,760	9,238	8,767
9	Rents and Leases	1,511	1,852	2,897	3,944	4,142
10	Costs Charged to Affiliates	(1,519)	(1,378)	(1,363)	(1,575)	(1,198)
11	Internal Allocations and Recoveries	(13,535)	(11,145)	(12,285)	(15,048)	(13,074)
12	Other	1,415	2,869	1,594	1,669	877
13	Total O&M Expense	59,194	60,606	55,126	53,528	54,699
	FTES	1,050	1,018	1,005	1,059	1,138

Witnesses: W. Akkermans
J. Alton
D. Lapp
J. Sanders

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 16: Is the proposed O&M budget for Operations appropriate?

Ref: Exhibit D1, Tab 15, Schedule 1 **[and Exhibit D1, Tab 16, Schedule 1]**

a) What is the salary and wage increase forecast for 2012 and 2013?

b) What is the impact on the revenue requirement of a 1% change in the salary and wage increase for both 2012 and 2013? Please provide the response for Salaries and Wages, Capitalization and Net Salaries and Wages, as defined in Tables 2 and 3.

c) Are the one-time costs of $1.7 million noted in paragraph 24 only for 2013? In other words, will this cost continue on an annual basis in 2014 and later years? If not, are there additional costs in 2014 relative to 2013 related to these outside services?

RESPONSE

a) Please see Exhibit A2, Tab 2, Schedule 1, page 10.

b) The salary increase sensitivity should be addressed at the overall company level rather than at the departmental level because merit increases are determined by HR and then applied across the Company. Departments just adhere to the HR guidelines.

Please refer to the response to Energy Probe Interrogatory #5 at Exhibit I, Issue D1, Schedule 7.5.

c) The $1.7 million noted in Exhibit D1, Tab 16, Schedule 1, paragraph 24 is a one-time cost and will not continue in 2014 and later years.

Witnesses: T. Adesipo
J. Alton
D. Lapp
B. Misra
J. Sanders
H. Wong

The $1.7 million is for the EnVision Application Operations Service contract renewal efforts, which include assessing and selecting the service provider and performing transition activities. These are one-time costs and in line with what are normally expected given the expiry of the existing contract.

Pending the assessment noted above, the Company is not able to quantify any other impacts on the annual operating cost of EnVision beyond 2013.

Witnesses: T. Adesipo
J. Alton
D. Lapp
B. Misra
J. Sanders
H. Wong

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 16: Is the proposed O&M budget for Operations appropriate?

Ref: D1/15/1, p. 7

Please provide details with respect to the 891 Error Response Team. Please provide any internal reports or other documents that include estimates of savings resulting from this initiative.

RESPONSE

The 891 Error Response Team dedicated resources to completing errors which prevented work from flowing to customer billing and the payment of contractor invoices. The number of 891 errors has significantly reduced from approximately 20,000 in 2007 to 4,000 in 2011. Efficiencies were realized through greater awareness and training. The number of FTEs needed to investigate and fix errors was reduced from fourteen in 2007 to seven at the end of 2011.

As of April 2012, the resources assigned to the 891 Error Response Team were reintegrated to the groups within the Work Management Centre ("WMC"), as a result of the decrease in the number of errors being generated. In the 2012 Estimate and 2013 Budget, there are four forecasted FTEs assigned to completing errors. The remaining three FTEs have been assigned to other functions within the WMC.

Witnesses: W. Akkermans
J. Alton
D. Lapp
S. Sanders

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 16: Is the proposed O&M budget for Operations appropriate?

Ref: D1/15/1, p. 8

Please provide details of the "lower future maintenance costs" arising out of the TC Module Upgrade program, and identify the reduction in budget included in the Test Year for this purpose.

RESPONSE

It is estimated that there will be approximately 5,000 TC Modules due annually starting 2013 and the cost to remove and repair just the electronic TC Module instead of the entire Rotary Meter Set with the old mechanical TC Module is significantly less. The cost to remove and repair the electronic TC Module is approximately $150 per unit, whereas the cost to remove and repair the entire Rotary Meter Set with the old mechanical TC Module is approximately $500 per Meter Set.

Witnesses: W. Akkermans
J. Alton
D. Lapp
S. Sanders

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 16: Is the proposed O&M budget for Operations appropriate?

Ref: D1/15/1, p. 10

Please provide a table, in the form of Table 1 that includes each of the years 2007 through 2013.

RESPONSE

Response to SEC Interrogatory # 3
Enbridge Gas Distribution Inc.
Operations, 2007-2013 O&M

Line No.	Particulars ($000's)	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Budget
1	Salaries and Wages	77,664	74,304	71,428	75,214	78,172	85,250	89,372
2	Capitalization	(47,263)	(44,549)	(42,457)	(44,128)	(45,652)	(50,875)	(53,377)
3	Net Salaries and Wages	30,401	29,756	28,971	31,086	32,519	34,375	35,995
4	Materials and Supplies	2,457	4,341	2,539	3,001	2,994	3,149	3,274
5	Outside Services	19,483	19,934	22,073	23,761	25,093	28,056	24,257
6	Consulting	359	918	1,278	1,387	998	1,230	1,263
7	Repairs and Maintenance	2,485	351	1,661	1,467	1,221	1,850	1,868
8	Fleet	8,767	9,238	7,760	7,705	8,496	9,057	9,250
9	Rents and Leases	4,142	3,944	2,897	1,852	1,511	2,193	2,244
10	Costs Charged to Affiliates	(1,198)	(1,575)	(1,363)	(1,378)	(1,519)	(1,102)	(1,117)
11	Internal Allocations and Recoveries	(13,074)	(15,048)	(12,285)	(11,145)	(13,535)	(13,564)	(13,896)
12	Other	877	1,669	1,594	2,869	1,415	1,606	1,645
13	Total O&M Expense	54,699	53,528	55,126	60,606	59,194	66,850	64,784
	FTES	1,138	1,059	1,005	1,018	1,050	1,179	1,207

Witnesses: W. Akkermans
J. Alton
D. Lapp
S. Sanders

SEC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 16: Is the proposed O&M budget for Operations appropriate?

Ref: D1/15/1, p. 13

Please explain why the 2011 collective agreement requires an additional 5 FTEs. Please provide the operational justification for these positions.

RESPONSE

Additional collective agreement employees are added within the envelope of the O&M Budget to meet the needs of the business resulting from Customer and System Growth, System Maintenance and for Succession Planning purposes.

Witnesses: W. Akkermans
J. Alton
D. Lapp
S. Sanders

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 17: Is the proposed O&M budget for Information Technology appropriate?

Ref: Ex. D1 /Tab 16/ Sch 1 / para 17 /

Please provide a commentary as to what measures Enbridge takes to manage Outside Services costs. What cost savings have been realized over the past 5 years as a direct result of managing Outside Services costs?

RESPONSE

As part of its efforts to manage Outside Services costs, IT Department Managers prioritize projects and programs in order to achieve cost savings.

For example, the renegotiations of programs with the Company's wireless services vendors. Enbridge completed an RFQ process with the vendors, with the result being that the Company has been able to generate savings of $1,000,000 over the three-year period (2011 to 2013) in savings from its wireless suppliers, Bell and Rogers. This savings has offset the increased use of smart phone devices.

The Company had been relying upon a privately owned EDACS network for communications with its field personnel. It evaluated upgrading or/replacing its existing EDACS hardware and undertook investigations into alternatives. The Company ultimately determined that the most cost efficient means of proceeding involved negotiating with Telus, an arrangement whereby Enbridge would obtain the same coverage but at significantly reduced costs both in terms of O&M and Capital. It is estimated that this change resulted in annual savings of $700,000. Further, the Company has avoided the need to replace/upgrade its EDACS system which it believes could have resulted in expenditures in excess of $15 million dollars.

The Company has relied upon IBM for seven years in respect of its IT Help Desk requirements. Management reviewed the costs of continuing with this relationship ultimately deciding to move the function in-house in December 2009. With help desk operations now being supervised by Enbridge internally, with outside contractors providing some required services, the result has been an improvement to service levels.

Witnesses: T. Adesipo
B. Misra
H. Wong

The improved functionality has generated greater internal users satisfaction by 3%, increased first call resolution by 42%, and it has increased the number of calls answered within 60 seconds by 18%. Also, the in-house help desk ability to handle calls increased by 10%. The estimated savings and cost avoidance as a result of taking this function in-house are expected to provide benefits from $130,000 in 2010, to $220,000 annually for the years 2013 through 2015.

Witnesses: T. Adesipo
B. Misra
H. Wong

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 17: Is the proposed O&M budget for Information Technology appropriate?

Ref: Ex. D1 /Tab 16/ Sch 1 / Table 2 /
Please provide an explanation for the increase in Outside Services costs.

RESPONSE

Enbridge Gas Distribution -IT Department
Outside Services costs - Explanation for Increase
2013 Test Year vs. 2012 Bridge Year

Line No.		($ millions)
1.	2013 Budget	23.8
2.	2012 Estimate	20.3
3.	Difference	3.5
	Reasons:	
4.	CIS Hosting and Support cost increase due to CIS hardware equipment going off warranty (CIS hosting and support cost was settled as part of the Customer Care/CIS settlement agreement (EB-2011-0226)	1.5
5.	EnVision application operations service contract renewal efforts to assess and select a service provider as well as to perform transition activities (refer to Exhibit D1, Tab 16, Sch 1/Line 24)	1.7
6.	Market rate changes pertaining to professional services, software and hardware maintenance costs	0.7
7.	Increase in Hardware maintenance cost as a result of hardware equipment going off warranty at end of 2012	0.1
6.	Reduction in contractors cost as a result of conversion of four FTEs	(0.5)
7.	Total 2013 vs. 2012 Difference	3.5

Witnesses: T. Adesipo
B. Misra
H. Wong

BOARD STAFF INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 17: Is the proposed O&M budget for Information Technology appropriate?

Ref: Ex. D1 /Tab 16/ Sch 1 / Table 3 /

Please provide a 5 year table of actual IT expenses in a similar level of detail as Table 3. Please provide commentary for any significant events causing spending pattern changes.

RESPONSE

1. Table 1 shows the IT Department actual expense over the five year period (2007 to 2011).

Table 1

IT Department 5 Year O&M (Actual)

Line No.	Component	2011 ($'000)	2010 ($'000)	2009 ($'000)	2008 ($'000)	2007 ($'000)
1	Gross Salaries & Wages	14,246	13,792	14,491	14,434	13,332
2	Capitalization	(6,328)	(5,953)	(8,188)	(8,265)	(6,539)
3	Net Salaries & Wages	7,918	7,839	6,303	6,169	6,793
4	Employee Training & Development	237	284	248	204	299
5	Outside Services	21,154	19,600	18,557	10,517	8,611
6	Telecommunications	3,258	3,586	3,617	3,596	3,764
7	Travel & Other Business Expenses	400	355	228	340	306
8	Costs charged to Affiliates	(2,473)	(2,585)	(2,024)	(1,411)	(1,525)
9	Other	17	8	8	4	8
	TOTAL	30,511	29,087	26,937	19,419	18,256
	FTEs	161	158	180	177	169

Witnesses: T. Adesipo
B. Misra
H. Wong

The principal drivers of the actual IT expenses are net salaries and wages and outside services, articulated below.

Net Salaries and wages include employees salaries and capitalization. Capitalization represents salaries for full-time employees of the Solution Delivery Team within Business Applications group whose salaries are 100% capitalized and charged to projects. The significant event drivers for the net salaries and wages are as follows:

Line No.	Notes:	
	Net Salaries & Wages (Line 3)	($ Millions)
1	2008 Actual	6.2
2	2007 Actual	6.8
3	Difference	(0.6)
	Reasons :	
4	Annual salary and wage merit increase of 3.3%	0.4
5	Increase of 8 FTEs due to ongoing implementation of New CIS project	0.7
6	Increase in capitalization driven by additional FTE assigned to New CIS project implementation	(1.7)
7	Total 2008 vs. 2007 Difference	(0.6)
8	2009 vs 2008 -No significant change.	
9	2010 Actual	7.8
10	2009 Actual	6.3
11	Difference	1.5
	Reasons :	
12	Annual salary and wage merit increase of 3.3%	0.5
13	Decrease of 12 FTEs (FTE assigned to New CIS Project moved back to other Departments)	(1.2)
14	Decrease in capitalization driven by completion of New CIS project	2.2
15	Total 2010 vs 2009 Difference	1.5
17	2011 vs 2010 -No significant change.	

Witnesses: T. Adesipo
B. Misra
H. Wong

Outside service costs represents costs paid to contractors, consultants or outsourcers, and fees paid to vendors for software and hardware maintenance. Contractor costs are incurred to perform desktop maintenance activities, augment existing support staff to handle extra workload, to back fill staff seconded to capital projects and to augment support in the early days of a new application going live. Consultants are engaged from time to time to assist with a particular expertise that the Enbridge IT staff might not possess. Outside Services also includes CIS hosting and application maintenance service cost. Table 2 (below) shows the significant event drivers for the outside services cost between 2007 and 2011:

Table 2
Outside Services
High-level Variance Between 2007 Actual and 2011 Actual

	$'M
2007 Actual	8.6
CIS Hosting and Application Maintenance Service cost as per Customer care Settlement Agreement (Exhibit N1, Tab 1, Schedule F in the EB-2006-0034 proceeding)	7.0
Contractor staff augmentation to support Affiliates and EFS. Cost recovered through Affiliates recovery (see Line 8- costs charged to Affiliates)	0.9
Software maintenance for new Business Applications and additional use of existing software	1.0
Hardware and software maintenance to extend the life of IT assets	0.9
Increase in Enterprise Applications footprint - related software and hardware maintenance, including EFS. These costs is partially offset by credits received through Corporate allocations.	0.9
Market rate changes pertaining to professional services, software and hardware maintenance cost	1.0
Software consolidation - software paid for by the Business in 2007 and prior, software management now taken over by IT Dept	0.2
Use of contract resource to augment FTE due to employee attrition	0.7
2011 Actual	21.2

Witnesses: T. Adesipo
B. Misra
H. Wong

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 17: Is the proposed O&M budget for Information Technology appropriate?

Ref: D1/16/1, p. 5

Please provide each of Tables 1 through 3, in the same format as in D1, Tab 15, e.g. including FTEs and capitalized amounts.

RESPONSE

Please find Tables 1 through 3, including FTEs and capitalized amounts:

Table 1

IT Department Budget for 2013

Component	**2013 Budget**
	($'000)
Salaries and Wages	16,633
Capitalization	(5,664)
Net Salaries and Wages	10,969
Employee Training & Development	547
Outside Services	23,754
Telecommunications	3,828
Travel and Other Business Expenses	573
Costs charged to Affiliates	(1,936)
Other	595
TOTAL	**38,330**
FTEs	**180**

Witnesses: T. Adesipo
B. Misra
H. Wong

Table 2

Variance between 2013 Budget and 2012 Estimate

Component	2013 Budget	2012 Estimate	Variance
	($)	($)	($'000)
Salaries and Wages	16,633	15,543	1,090
Capitalization	(5,664)	(5,473)	(191)
Net Salaries and Wages	10,969	10,070	899
Employee Training & Development	547	540	7
Outside Services	23,754	20,304	3,450
Telecommunications	3,828	3,744	84
Travel and Other Business Expenses	573	570	3
Costs charged to Affiliates	(1,936)	(1,876)	(60)
Other	595	307	288
TOTAL	**38,330**	**33,658**	**4,672**
FTEs	**180**	**174**	**6**

Witnesses: T. Adesipo
B. Misra
H. Wong

Table 3

Variance between 2012 Estimate and 2011 Historical

Component	2012 Estimate	2011 Historical	Variance
	($)	($)	($'000)
Salaries and Wages	15,543	15,073	470
Capitalization	(5,473)	(5,742)	269
Net Salaries and Wages	10,070	9,331	739
Employee Training & Development	540	204	336
Outside Services	20,304	18,993	1,311
Telecommunications	3,744	3,451	293
Travel and Other Business Expenses	570	587	(17)
Costs charged to Affiliates	(1,876)	(1,608)	(267)
Other	307	-	307
TOTAL	**33,658**	**30,957**	**2,701**
FTEs	**174**	**167**	**7**

Witnesses: T. Adesipo
B. Misra
H. Wong

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 17: Is the proposed O&M budget for Information Technology appropriate?

Ref: D1/16/1, p. 7

Please provide any evidence the Applicant has to support the claim that "security threats from outside…are becoming more frequent".

RESPONSE

Advisories from the US Department of Homeland Security ("DHS") and from the Canadian Cyber Incident Response Centre ("CCIRC") have increased significantly over the past 18 months as utilities and pipeline companies have become key targets in many hactivist (hacker-activist) campaigns, such as that from the group Anonymous, and from terrorist and nation state-sponsored campaigns that target critical infrastructure control systems. Reports show a severe increase in the number of compromised systems/networks of many large enterprise corporations and governments, resulting in the exposure of intellectual property and customer personal information. It is the responsibility of the Enbridge Gas Distribution Inc. ("Enbridge") Information Technology ("IT") Security team to perform the investigative due diligence as per these federal advisories. These investigations take considerable time and effort from multiple team members to complete and report findings to IT Management.

Enbridge's IT Security team has also been monitoring and responding to many direct attack attempts as alerted by their security control technologies, but the team does not have the capability to perform continued security intelligence gathering from the many control logs and reports. One example of the threat increase is that malware counts for 2012 Q1 have exceeded the total malware count for all of 2011. The Enbridge report for the month of June 2012 is showing a 400% increase in malware infection attempts over the previous months. Another example of attack increase is that during the first half of 2012, there have been ongoing and increasing attempts from the outside to cause a denial of service on Enbridge's internet connection – a vital communication route to Enbridge customers and business partners.

Witnesses: T. Adesipo
B. Misra
H. Wong

There is increased pressure on IT Security organizations globally to continue to remain up-to-date on new threats and security technologies. From industry feeds and 3rd party assessments, the Enbridge IT Security team has implemented many new security technologies to protect Enbridge Gas Distribution Inc.'s computing assets to keep in step with the new threats and vulnerabilities. Old technologies are not removed as the protection they provide is still required. Each new technology creates the additional overhead of system management and administration.

Keeping pace with the ever-increasing threat landscape and continuing the support and protection of Enbridge computing assets is not sustainable with the current IT Security staffing levels. Hence, the need to add one Support Analyst to strengthen the IT Security Team to ensure IT continues to be safe and secure.

Witnesses: T. Adesipo
B. Misra
H. Wong

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 17: Is the proposed O&M budget for Information Technology appropriate?

Ref: D1/16/1, p. 9

Please provide more details on why Employee Training and Development required a 165% increase from 2011 to 2012.

RESPONSE

The 2011 and 2012 budgeted employee training and development are comparable (please see Table 1). The budgeted employee training and development is based on FTE count and averages $3,000 per employee, about 1 to 2 weeks of personal training and development per employee. However, due to business priorities, employees ended up spending less time in 2011 on training and development then budgeted. Hence, there is a significant increase when 2011 Actual is compared to 2012 Budget.

The Company fully anticipates that employees will attend their training in 2012.

Table 1
Employee Training and Development (Budgets: 2010 -2013)

Budget Item ($'000)	2013	2012	2011	2010
Employee Training and Development	547	540	574	543

Witnesses: T. Adesipo
B. Misra
H. Wong

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: Ex. D1 /Tab 17/ Sch 1 / Tables 3 & 4 /
With reference to Tables 3 & 4, please identify and explain any Non-utility expense budget items.

RESPONSE

There are no non-utility expense budget items in the 2013 Test Year Budget and the 2012 Estimate for Business Development and Customer Strategy ("BDCS"). However for the 2011 Historical Year (Table 4, Line 8), $95,000 is identified as a non-utility item for Green Energy. The group was involved in two Green Energy projects: District Energy and Biogas Services. The $95,000 is also referenced in the Green Energy evidence EB-2011-0354, Exhibit D2, Tab 8, Schedule 1, page 6.

The 2011 actual costs for Green Energy have been updated to $106,000. This can be found in the updated Operating Maintenance and other costs (filed: 2012-06-01, EB-2011-0354, Exhibit D1, Tab 3, Schedule 1, page 26, Line No. 23) and in EB-2012-0055, Exhibit D, Tab 1, Schedule 3, page 5.

Witnesses: L. Kennedy
P. Squires

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: Ex. D1 /Tab 17/ Sch 1 / para 38 /
Please explain the "Conservation Services" budget variances in 2013.

RESPONSE

The 2013 budget variance for "Conservation Services" is explained in Exhibit D1, Tab 17, Schedule 1, paragraph 28, and reproduced here;

> The 2013 Test Year O&M budget for Conservation Services is $1.5 million and the 2012 Estimate Year O&M budget is $7.0 million. The variance is a net decrease of approximately $5.5 million. This is primarily due to the wind-down of the HPNC Program with the OPA in December 2012. HPNC Program costs will be recovered on a fully allocated costs basis.

Witnesses: L. Kennedy
P. Squires

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: D1/T17/S1/p. 3

Please provide the 2013 budget for "Business and Market Development". To what extent are those activities allocated to the un-regulated side of the business? How many of the employees in this group provide services to Enbridge Inc.?

RESPONSE

The 2013 Test Year budget for Business and Market Development is $5,427,000. No activities in this group are allocated to un-regulated businesses. Market Development does not have any employees providing services to Enbridge Inc., and Business Development has 0.4 of one FTE that provides services to Enbridge Inc..
The costs associated with this FTE have been eliminated and charged to Enbridge Inc..

Witnesses: L. Kennedy
P. Squires

CCC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: D1/T17/S1/p. 8

Please provide the 2013 budget for the "Strategy Research and Planning Group". To what extent are those activities allocated to the un-regulated side of the business? How many employees in this group are providing services to Enbridge Inc.?

RESPONSE

The 2013 Test Year Budget for Strategy Research and Planning is $1,783,000. No activities have been allocated to un-regulated business and less than 10% of one FTE provides services to Enbridge Inc.. The costs associated with this FTE have been eliminated and charged to Enbridge Inc..

Witnesses: L. Kennedy
P. Squires

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: Exhibit D1, Tab 17, Schedule 1

Has EGD included any amount in the costs that flow through to the test year revenue requirement for Energy Technology Innovation Canada related costs? If yes, please identify the amount and where in the evidence this is referenced.

RESPONSE

There is no O&M cost associated with ETIC. $100,000 has been identified for ETIC in the 2013 Test Year Capital Budget. This amount is grouped with system improvements and upgrades. Refer to EB-2011-0354, Exhibit B1, Tab 2, Schedule 1, page 3.

Witnesses: L. Kennedy
P. Squires

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: D1/17/1, p. 3

Please provide further details on the "project screening tool", including a copy of the tool if it exists in an easily accessible format (like Excel).

RESPONSE

The Project Screening Tool is comprised of four sequential stages separated by a series of go/no-go questions. For a project to successfully ascend to higher stages, the project sponsor faces increasing levels of rigor to ensure that the concept is sound and the business case is ultimately sustainable. An internal project screening committee, comprised of senior managers within the Business Development team has been established to carry out the review process.

Attached please find the Project Screening Tool.

Witnesses: L. Kennedy
P. Squires

Gate-1: Self-Assessment

Description: Decision-point advancing from Stage-0 ("Ideas") to Stage-1 ("Scoping")

Instructions to Project Owner:

1. Complete following table:

Date of Project Submission to Gate-1:		
Name of Project:		
Name of Project Owner:		
Name of Project Sponsor:		If applicable
Project Description (150 words max)		

2. Respond to the "Project-Fit Questions" below
3. E-mail filled-out table and answered questions to BD Manager

Process:

a) Once received, BD Manager will send completed table + answered questions to members of Project Screening Committee (PSC) for review
b) BD Manager will e-mail back to Project Owner within 2-weeks of submission-date with go, no-go or further discussion decision from PSC
c) If decision is go, then Project Owner is to proceed to and prepare for Stage-1 ("Scoping"

Project-Fit Questions:	**Yes or No**
1. Project relates to BD and/or MD activities (Yes/No)?	
2. Project is aligned with EGD's line of business strategies (including timing) within either of the following categories: (i) gas distribution, (ii) alternative energy delivery service, (iii) green energy, (iv) transportation? Consider: -whether the project leverages EGD's skill-sets, assets, and whether it advances the company) -whether the investment is defensive or offensive w.r.t. competition (e.g. investing funds to better understand new or increasing competitive threat)	
3. Project is or could realisticaly be rate-basable? If not, consider if there are any other risk-mitigating factors available (e.g. grants, incentives, gov't-backed purchasing agreements, co-investors, low risk opportunity, etc.?	
4. There are no show-stoppers at the outset (e.g. high-level financials, fundamental technical issues, equipment availability, imcompatible legislation, unwilling stakeholders, etc.)? A show-stopper could also include a competitive solicitation document that is either unclear/difficult to understand and/or contains significant requirements that do not fit with EGD's business, and/or contains unrealistic terms & conditions and targets	

Project-Fit Requirements

All questions must be answered in the affirmative ("Yes") in order to proceed to Stage-1 ("Scoping")

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D18
Schedule 14.1
Attachment Page 1 of 7

Gate-2: Portfolio Steering Committee Assessment

Description: Decision-point advancing from Stage-1 ("Scoping") to Stage-2 ("Business Case")

Instructions to Project Owner:

1. Send BD Manager completed Scoping information package which should include:

Decsription of project:	a) what is project's purpose?
	b) what is the business need in the marketplace?
	c) what is the target market/audience?
SWOT analyses	
Business model:	a) sketch out conceptually how the business model works
	b) run a simple set of calculations
	c) state what the anticipated results are

2. Complete the table below:

Date of Project Submission to Gate-2:		
Name of Project:		
Name of Project Owner:		
Name of Project Sponsor:		If applicable

3. E-mail completed table and scoping information to BD Manager

Process:

a) Once received, the BD Manager will forward the scoping information to the members of the PSC for review

b) PSC will review information by assessing it against the Scoring Categories shown below

c) BD Manager will e-mail back to Project Owner within 2-weeks of submission date with a go or no-go decision from the PSC. The decision will include comments, score results and possible recommendations/suggestions

d) If project receives at least the minimum score as per Project Scoring-Requirement Criterion below, the Project Owner is to proceed to and prepare for Stage-2 ("Business Case")

Scoring Categories:

		Numeric Score (0 = missing, 3 = satisfactory, 5 = very strong)	**Example of areas to consider in scoring:**
Decsription of Project:	Areas of Consideration		
	1. Project's purpose		-how clearly has Project Owner described really what the project is intended to do? Has the case been clearly and understandably articulated?
	2. Business need - marketplace, company		
	3. Target audience - identified, accessible, realistic		
	sub-total (min.9-points required)	**0**	

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D18
Schedule 14.1
Attachment Page 2 of 7

		Yes	No
Principle Categories	**Project location** - located in jurisdiction where there are existing Enbridge assets and/or activities?		
	Company relevance - project is aligned with the company's core activities?		
	Project financials - project is designed to generate revenue, lower costs or combination (i.e. improve net income)?		
	Level of regulatory engagement - project does not need any or a lot of "heavy regulatory lifting" to change legislation/policy?		
	Project leverage - project leverages company assets to fullest extent (e.g. people skills and resources, physical assets, etc.)? Have all of the key stakeholders been contacted about this project?		
	Environment, Health and Safety - project considers and aligns with EH&S company policies?		
	Risk mitigation - project is designed to manage level of risk exposure (e.g. business, physical, legal) to company?		

Project Scoring-Requirement:

The project must receive a min. score of 9 out of a maximum of 15 under "Description of Project" AND 4-"Yes'" out of 7 under "Principle Categories" in order to proceed to Stage-2 ("Business Case")

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D18
Schedule 14.1
Attachment Page 3 of 7

Gate-3: Portfolio Steering Committee Assessment

Description: Decision-point advancing from Stage-2 ("Business Case") to Stage-3 ("BVA")

Instructions to Project Owner:

1. Send BD Manager completed Business Case. The following are the themes that the PSC will be assessing in the review of the Business Case document:
    1. Investment has value and importance to the company
    2. Risks are properly assessed and the actions/choices are appropriate
    3. Project will be properly managed
    4. Company has/will have the capability to deliver the results
    5. Dedicated resources will be working on the highest value opportunities

2. Complete the table below:

Date of Project Submission to Gate-3:		
Name of Project:		
Name of Project Owner:		
Name of Project Sponsor:		If applicable

3. E-mail completed table and scoping information to BD Manager

Process:

a) Once received, the BD Manager will forward the Business Case to the PSC for review

b) PSC will review information by assessing it against the Scoring Categories shown below

c) BD Manager will e-mail back to Project Owner within 4-weeks of submission date with a go or no-go decision from the PSC. The decision will include comments, score results and possible recommendations/suggestions

d) If project receives at least the minimum score as per Project Scoring-Requirement Criterion below, the Project Owner is to fill out the Business Valuation Assessment form (i.e. Stage-3 ("BVA"))

Scoring Categories:

		Numeric Score (0 = missing, 3 = satisfactory, 5 = very strong)	**Example of areas to considerin scoring:**
Decsription of Project:	Areas of Consideration		
	1. Executive Summary		-how clearly has Project Owner described really what the project is intended to do? Has the case been clearly and understandably articulated? What's is the Project Owner asking the company to embark upon?
	2. Business need - from company's perspective		
	3. Target audience - identified, accessible, realistic		
	4. Customer value proposition		
	sub-total (min.16-points required)	**0**	
SWOT Analyses:	SWOT Analysis		
	1. Strengths		-the Project Owner will be expected to expand on their earlier work in this area by addressing any shortfalls identified as well as crystalize the details: -has the Project Owner comprehensively identified the areas in question? -has comprehensive consideration been made on how the company could mitigate risks? -are any cases made for how these areas may change over time?
	2. Weaknesses		
	3. Opportunities		
	4. Threats		
	sub-total (min.16-points required)	**0**	

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D18
Schedule 14.1
Attachment Page 4 of 7

Final Business Model:	1. The final business model is realistic. It is described clearly and convincingly.		
	2. The workings of the final business model are demonstrated with scenario examples.		
	3. The business case includes convincing discussions on how the final business model is sustainable or when it is expected to be.		
	4. The business case articulates what assumptions have been made in the final business model. It considers rigorously which assumptions are most likely to have a significant impact on the performance of the project. The assumptions, at least the key drivers, are realistic.		-the Project Owner is expected to make a strong case for how commercially viable the Project will be to the company. Consider that the resources (e.g. money, time, people, other assets) being sought for this Project were your own: would you invest in the Project?
	5. Sensitivity analyses demonstrate what variables drive the business model's results to the greatest extent. These results of these analyses are discussed in the SWOT chapter within a heading of "Mitigating Risk".		
	sub-total (min.20-points required)	**0**	
Project Plan	1. The business case describes the internal and external resources (people) that will be required - when and for how long. These resources are realistic to acquire (# and skill-set).		
	2. The business case includes sets of timelines and milestones. They are realistic.		
	3. The business case provides a list of what measures and how will be tracked to determine the project's performance		
	4. It is clear which departments, individuals will be accountable for the project's success		
	sub-total (min.16-points required)	**0**	
Financials	1. Proforma financial tables show at least 10yr income and statement of cashflows - the financials also include a summary for Rev, O&M and EBITDA for integration into the BVA stage		-the PSC will be looking for quality financial proformas which show acceptable returns for the company -they will be looking to see if the Project Owner has a proper handle on the business
	2. The financials show that acceptable results are achievable with this project (e.g. revenue, EBITDA, IRR, NPV)		
	3. Sensitivty analyses show that what variables drive the Project's performance the greatest		
	sub-total (min.12-points required)	**0**	

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EH&S	1. The Project Owner has aligned the project's execution and ultimate life as a line of business with company's EH&S policies as well as EI's "6 Lifesaving Rules"?		-the PSC will be looking for the project to strongly address this area. At the very least, they will expect to see documented that the EH&S department has been fully engaged in the project.
	sub-total (min.4-points required)	**0**	
Other Misc. Information	1. The Project Owner has included other information to support the business case (e.g. customer testimonials, mock-ups, test results, discussions on other areas/companies where this project has taken place, etc.)		
	2. The business case is interesting and self-promoting. The Project Owner sounds enthusiastic.		
	3. Open comment with any content the Reviewer on the PSC wishes and feels would contribute appropriately to the Project's business case's overall score		
	4. The business case is adaptable to changing environments. The project is flexible and could be redirected or redesigned in some respect.		
	sub-total (min.16-points required)	**0**	
	Grand Score Total:	**0**	

Project Scoring-Requirement:

The project must receive a total score of 101 out of a maximum of 125 in order to proceed to Stage-3 ("BVA"); Lorraine Kennedy will provide instructions, timelines and latest template to complete the BVA

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D18
Schedule 14.1
Attachment Page 6 of 7

Gate-4: Portfolio Steering Committee Assessment

Description: Decision-point advancing from Stage-3 ("BVA") to Stage-4 ("Implementation")

Description: Project Owner has completed and submitted the BVA to BDMD's Portfolio Asset Management Group rep, Lorraine Kennedy. The committee provides a go/no-go descision based on the project's own BVA merit and also other projects' that are seeking company resources at the same time.
Successfull projects will proceed to Stage-4 to implement its roll-out.
-Project Owners must adhere to the appropriate company capital-requisition protocols.
-Project Owner must adhere to timelines and milestones specified in Business Case
-Project Owner must implement their safety compliance procedures as per the counsel of the EH&S department

Filed: 2012-08-03
EB-2011-0354
Exhibit I
Issue D18
Schedule 14.1
Attachment Page 7 of 7

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: D1/17/1, p. 4

Please provide any reports or other documents dealing in whole or in part with the savings generated by the "program planning tool".

RESPONSE

The Project Screening Tool has only recently been developed and not officially launched. As such, no new project has officially been reviewed using the tool. Internal communications and education are expected to be delivered later this year.

Witnesses: L. Kennedy
P. Squires

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: D1/17/1, p. 12

Please advise why FTEs decrease by only 1 from 2012 to 2013 when the Conservation Services budget declines by $5.5 million.

RESPONSE

The decrease of one FTE is a net total for Business Development & Customer Strategy ("BDCS") which includes Business Development, Marketing Development, Sales, and Strategy, Research and Planning ("BDCS Core"), as well as Conservation Services and Demand Side Management ("DSM"). There was a reduction of three FTE's in Conservation Services resulting primarily from the wind-down of the High Performance New Construction ("HPNC") Program with Ontario Power Authority ("OPA") in December 2012, which was partially offset by FTE increases in other BDCS departments.

Witnesses: L. Kennedy
P. Squires

SEC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Ref: D1/17/1, p. 15

Please advise how the ratepayers benefit from the $1 million increase in budget to research new business and market development opportunities.

RESPONSE

Enbridge Gas Distribution's Business Development activities are required for the development of future growth, energy efficiency and sustainability opportunities. The 2012 Estimate when compared to 2011 Historical is higher by $1 million due to the change in activities undertaken by the group and the level of project activity anticipated as a result of evolving industry, economic and fuel-price circumstances. The future activities of Business Development are focused on: Distributed Energy (DE), Distributed Generation (DG), Energy Efficiency (EE), Liquefied Natural Gas (LNG), Net Zero and Low Energy Homes, Testing and Sampling procedures for Natural Gas, Renewable Natural Gas (RNG), and Natural Gas Research.

The nature of these areas of research, study and projects are intended to enhance and complement the natural gas distribution function of the Company, and provide alternative uses and new markets for natural gas. This occurs through the application of new technology, improved energy efficiency, and the substitution of other energy forms for gas. These activities serve to enhance the sustainability of the natural gas distribution business.

The Business Development opportunity areas evolve over time. Opportunities must be evaluated as standalone projects and in aggregate to determine if there are synergies that could create additional benefits and/or reduce costs for customers. One example is in the transportation market, where LNG provides the only alternative to diesel in the large truck market. LNG can significantly reduce GHG emissions, LNG can be used for remote communities, and in system supply may enhance seasonal reliability and lower

Witnesses: L. Kennedy
P. Squires

costs. Additionally, low gas commodity prices have spurred customer interest in two key areas where activity has been limited in recent years: on-site gas-fired generation and gas cooling. Both technologies offer the opportunity for a long-term increase in volumes and load factor benefitting all customers, and costs reductions for participating customers.

Witnesses: L. Kennedy
P. Squires

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 18: Is the proposed O&M budget for Business Development & Customer Strategy, including Energy Technology Innovation Canada ("ETIC") related amounts, appropriate?

Reference: Exhibit D1 Tab 17 Schedule 1

a) Is there any provision for 2013 Energy Technology Innovation Canada (ETIC) costs? If please identify the evidence references and amounts.

b) Provide a copy of the CGA "regulatory ask" paper for ETIC (See Union IRRs in EB-2011-0210).

c) Provide details of EGDI/EI participation in ETIC.

RESPONSE

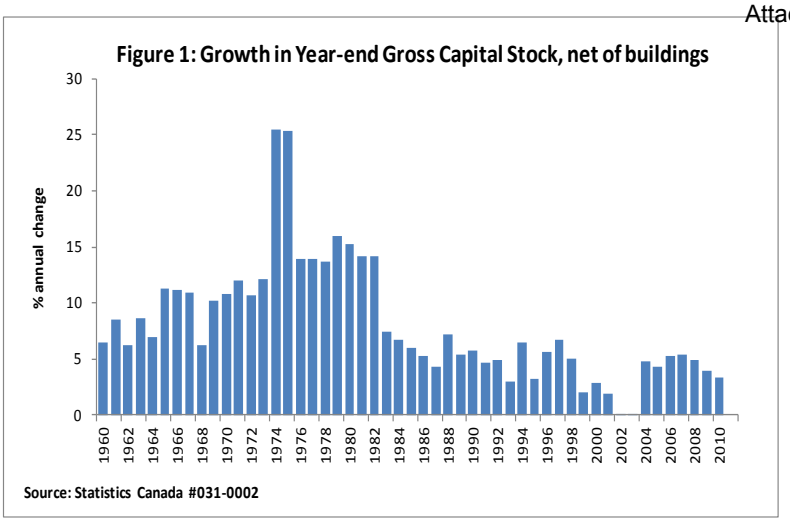
a) See the response to Energy Probe Interrogatory at Exhibit I, Issue D18, Schedule 7.1

b) Attached is a copy of the CGA "Regulatory Ask" draft paper. This draft was a "work in process" and has not been finalized by the CGA.

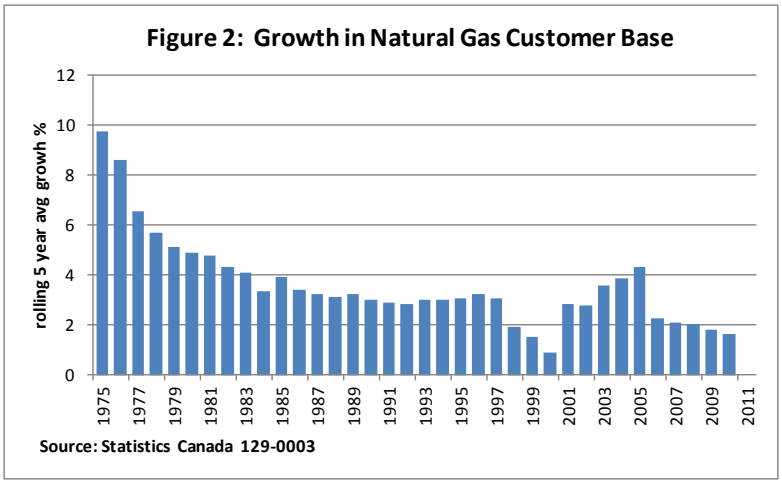
c) EGD has provided human resources to ramp up and operate ETIC. An EGD VP has been and continues to be a member of the ETIC steering committee. The role of the Steering Committee is to provide governance, resources, the operating budget, and long-term direction. An EGD Director has been and continues to be on the ETIC Operating Committee. The operating committee is responsible for setting research priorities, allocating project budget monies, and providing technical direction for the projects and operation of ETIC. An EGD manager has been assigned the role of ETIC Business Process Manager. The Business Process Manager is accountable for all monies budgeted and spent, all contracts developed, negotiated, signed, and executed by ETIC.

Witnesses: L. Kennedy
P. Squires

Canada's national natural gas distribution system is entering a period of increased renewal. Originally put in place over the 1960's and 1970's (see Figure 1) an increasing proportion of Canada's natural gas grid is now approaching the end of its designed lifespan. This means an increase in the annual quantities of pipes, fittings and fixtures that will need to be replaced.



The current system was originally built at a time when customer bases were growing more rapidly (see Figure 2), were easier to attached, and vast undeveloped energy from both hydrocarbon and hydraulic sources were available to meet growing demand. But fast forward forty years and we find that, while Canada still has abundant natural gas resources, there is no longer a large and fast growing "yet to be attached" customer base and renewing the existing systems means working in the very heart of the Canadian urban and sub-urban landscape.



But this renewal affords the opportunity for Canada's natural gas LDC's to take advantage of forty years of innovation in energy system and energy end use design to infuse their systems and consumers homes and businesses with new innovations and technologies that will create a more integrated, efficient, clean, and more affordable energy system

For Canada's regulated natural gas utilities pushing new technology is something of a reversal. Since the days of "unbundling" Canada's regulated natural gas monopolies LDCs have been limited in the research and development spending that they could recover in rates. But by pooling their collective technology and innovation spending resources LDCs can leverage ratepayer funding with shareholder and government monies to the collective benefits of energy consumers across Canada.

Certainly cleaner and more efficient energy services will have broad public benefits including lower GHG and other emissions. But the questions remain ...
Why should LDC monopolies be moving into technology development and deployment? And,
Why should LDC ratepayers foot the technology and innovation bill?

The answer follows.

1. LDC's provide an existing connection and relationship to millions of Canadian energy consumers

Natural gas is used in virtually every region of Canada. Natural gas utility franchise areas cover the country from coast to coast to coast (see Figure 3) delivering safe, clean, versatile, affordable natural gas energy to over 20 million Canadian in over 6.3 million homes, businesses, schools, and other institutions. Natural gas meets over 30 percent of Canada's energy needs making it the second more used energy form in Canada, after refined petroleum products.

Figure 3: Natural Gas LDC Franchise Areas

This comprehensive relationship with Canada's energy consumers highlights the value in having natural gas distribution utilities play a key role in the development and deployment of new energy technologies. Technologies brought forth by the LDC will reach more consumers more quickly and be able to deliver the economic, environmental and societal benefits more quickly and more comprehensively than any new enterprise.

2. LDCS's undergo regular regulatory oversight and review

Canadian natural gas utilities have decades of operational excellence under the watchful eye of both economic and operational regulatory authorities. Any major action taken by a natural gas utility, anywhere in Canada goes through an extensive regulatory review process. This existing oversight would be brought to bear on any monies used for innovation and technology support.

This degree of governance provides customer protection and allows any concerned party to appear before the appropriate regulatory authority to express their view, submit expert opinion, and supporting information to test the claims and actions and expenditures of the utility. Indeed it is commonplace for Canadian natural gas utilities to face such regular scrutiny and these regulatory review processes have well established methods and rules that are backed by the force of law.

3. LDCs are energy system program finance and business risk experts

Allowing well financed and stable LDC to initiate technology and innovation programs helps limit the program's risk. LDCs participation will leverage ratepayer's investment helping to mitigate any business and financial risks associated with new technologies and innovations. LDCs financial expertise can further limit potential cost consequences to the public. LDC participation will allow development and deployment of a number of innovations and new technologies that might not otherwise be viable. Once established and successful, these innovations could remain under LDC control or be turned back to private sector markets and operators.

4. LDCs have extensive energy service & system operational expertise

LDCs employ a highly skilled workforce, directly employing tens of thousands of energy systems experts in the form of engineers, gas fitters, and natural gas technicians' and others. Canadian natural gas LDCs have provided billions of hours of safe and reliable natural gas energy services to Canadians.

This expertise makes natural gas systems and their LDC franchise operators the ideal venues for the "real world" development and delivery of new, beneficial energy end use technologies. LDC's, through cooperative joint efforts, can bring new energy end use technologies into operation more quickly and safely than any other energy market player.

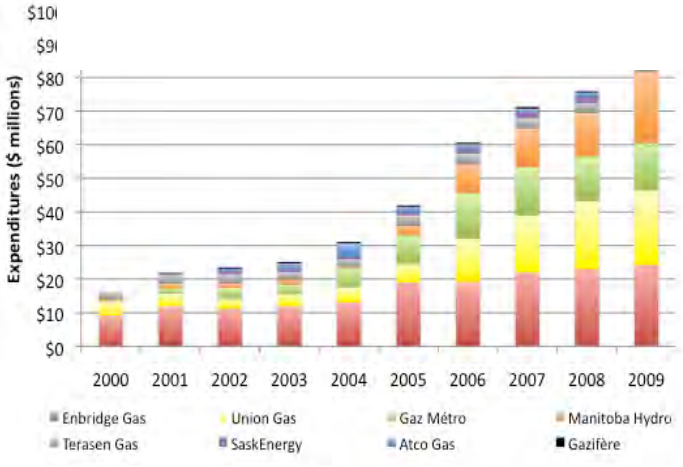
By letting LDCs return to technology research, development, and deployment they can pool their energy systems expertise and leverage their collective efforts to provide the maximum benefits available from the deployment of new energy systems and services.

5. LDCs have a history of success operating rate payer supported programs

Canada's natural gas LDC's have shown they are innovative and, when allowed, are willing and able to make appropriate investments in cleaner, more productive energy systems and technologies.

For example from 2000 through 2009, more than 459 million dollars were invested in demand side management conservation (DSM) activities by natural gas utilities in Canada, saving almost 1.8 billion cubic metres of natural gas [1] (see Figure 4).

Figure 4: DSM expenditures by company (2000 - 2009)[1]



LDCs, regulators and consumer groups have evolved a model for such programs that allows the interests of all parties to be reflected and protected. Recreating a similar mechanism outside the regulated utility model would be unnecessarily costly and duplicative. DSM programs are but one example of the history of success that Canada's natural gas LDC's have in bringing new and innovative ideas to fruition within the regulated utility business model.

[1] Canadian Natural Gas DSM Activities 2000-2009, IndEco Research,

CONCLUSIONS AND SUMMATION

Canada's natural gas LDCs are key investors in the Canadian energy marketplace. Their existing investments, financial and operational expertise, and connection to over 20 million Canadians in over 6 million homes, businesses, industries, and institutions make them an ideal interlocutor to advance energy innovation and technology in Canada.

The consumer protection afforded by the existing regulatory oversight framework will provide the due diligence to monitor and ensure that ratepayers benefit from LDC investments in innovation and technology and that these investments are both prudent and well planned.

In short, Canadian natural gas utilities' 100 plus years of energy service system construction and safe operation make them the most logical partner to bring innovation and technological advancements safely into the existing energy services system in Canada. Doing so will lead to a more efficient, cleaner integrated energy services system.

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: Ex. D1 /Tab 18/ Sch 1 / para 8 /

Please quantify and explain the effects of any collective labour agreements on the salaries, wages and benefits, and other employee related costs on the 2013 budget.

RESPONSE

A new Collective Agreement was established in 2011, expiring December 31, 2013. The negotiated salary adjustment is 2% effective January 1, 2013 and 1% July 1, 2013. No other compensation related adjustments occurred. There were no changes to the levels or design of the benefit programs. The effects on benefit related costs would be higher allocation of dollars in which to purchase benefits through the flexible benefit plan program. This would reflect an overall increase of approximately $72,000.

Witness: S. Trozzi

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: Ex. D1 /Tab 18/ Sch 1 / para 26 /

With respect to the request for the increase in Pension costs recovery, please explain why the issue of pension underfunding exists when the Board recently rejected the Company's' request for a similar pension related cost Z factor in proceeding EB-2011-0277.

RESPONSE

Please refer to Board Staff Interrogatory #6 at Exhibit I, Issue D1, Schedule 1.6 and Board Staff Interrogatory #2 at Exhibit I, Issue D4, Schedule 1.2.

Witnesses: S. Kancharla
R. Lei
A. Patel

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: D1/T3/S1/p. 12

Please provide a schedule setting out the number of FTEs added each year since 2007. Please provide the information by category - Management, Supervisory, Union and Total.

RESPONSE

Please see the response to Board Staff Interrogatory at Exhibit I, Issue D1, Schedule 1.5.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

CCC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: D1/T3/S1

Please describe any efficiency gains EGD achieved during the IRM period with respect to Human Resources Costs. How have those efficiencies translated into a reduced revenue requirement for 2013?

RESPONSE

Although Human Resources costs have not declined during the IRM period, there has been a greater emphasis placed upon costs associated with the budget, such as, education for employees on the cost of benefits so they can make educated choices for utilizing the most cost effective benefit provider.

A greater emphasis has been placed on contractor utilization in the Facilities department, including heightened efforts to contract the most cost effective provider while ensuring the quality and timeliness of the work. HR and Facilities continue to look for efficiencies in achieving the required results to ensure EGD performance.

For a broader discussion of efficiencies please see the response to CCC Interrogatory #2 at Exhibit I, Issue O3, Schedule 5.2.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Revenue
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: Exhibit A1, Tab 10, Schedule 1

a) Please confirm that all of the positions shown on Schedule 1 are positions at Enbridge Gas Distribution Inc. ("EGD").

b) For each position shown in Schedule 1 that provide services to affiliates of EGD, please indicate how the salaries, wages and benefits costs of the position are allocated between affiliates and EGD.

RESPONSE

a) All positions shown at Exhibit A1, Tab 10, Schedule 1 are EGD positions.

b) Each position at EGD that provides a service to an affiliate has a Service Level Agreement in place. This Service Level Agreement specifies an hourly rate that is charged to the affiliate for services provided. This hourly rate is based on the market rate or fully allocated costs where appropriate.

Witnesses: S. Kancharla
R. Lei
S. Trozzi

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: Exhibit D1, Tab 18, Schedule 1

Please provide a table that shows the additional costs and savings that will be realized in 2013 as noted in paragraph 6. Please indicate where these savings haven been reflected in Tables 2 and/or 3.

RESPONSE

Lease cost savings totaling $915,496 are expected to be realized in 2013 as a result of the consolidation of several facilities into the new multi-purpose facility. These savings have been reflected in the Rent and Leases 2013 Budget provided on Line No. 5 in both Table 1 and 2 of Exhibit D1, Tab 18, Schedule 1.

Savings realized in 2013 with respect to travel time and overall organizational efficiency gains as a result of the consolidation do not impact the 2013 O&M budget for Human Resources. The business case for the new multi-purpose facility has been provided in the response to CCC Interrogatory #3 at Exhibit I, Issue B1, Schedule 5.3. and it provides details of expected savings associated with travel time and overall organizational efficiency gains.

Witness: S. Trozzi

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: D1/18/1, p. 2

Please provide the business case or other proposal document for the new multi-purpose facility.

RESPONSE

Please see Consumers Council of Canada Interrogatory #3 at Exhibit I, Issue B1, Schedule 5.3.

Witness: S. Trozzi

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: D1/18/1, p. 2

Please provide a table setting out the nature and amount of all payments made to affiliates of the Applicant, including but not limited to amounts payable under RCAM, related to the new multi-purpose facility

RESPONSE

There have been no payments made to affiliates related to the new multi-purpose facility.

Witnesses: S. Trozzi
B. Yuzwa

SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: D1/18/1, p. 4

Please provide a breakdown of the $7.7 million of other expenses into the categories listed in para. 14.

RESPONSE

Breakdown of $7.7M of Other Expenses:

Consulting	568
Employee Training and Development	2,436
Fleet	31
Materials and Supplies	471
Memberships	12
Other	2
Travel and Other Business Expenses	343
Provision for recognition for overtime	2,250
Severance	2,000
Charges to Pension Plan	(370)
Total	7,743

Witness: S. Trozzi

SEC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Ref: D1/18/1, p. 7

Please provide a more detailed explanation of the "greater emphasis placed upon performance management", and the forecast costs that are to result from that.

RESPONSE

The Company is placing a greater emphasis on performance management ensuring employees are achieving the required results. Employees are expected to achieve their performance objectives, which assists the Company in achieving operational and financial results.

As the performance management process continues to be refined, by providing leaders additional training and education to ensure employees are productive and effective in the execution of business objectives, Enbridge expects to identify some under-performing employees. As a result, severance costs are expected to increase over the next two or three years.

Witness: S. Trozzi

VECC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 19: Is the proposed O&M budget for Human Resources appropriate?

Reference: Exhibit A2 Tab 3 Schedule 2 Page 7

a) How is EGD proposing to recover pension costs over the period 2013-2017?

b) How often will updates to the Mercer Report and estimates be filed during that period?

RESPONSE

a) As indicated in the evidence referenced, Enbridge is requesting the approval of the use of an accrual method of accounting for pension costs for rate making purposes for 2013. As shown in that evidence Enbridge estimates the use of the accrual method, over the years 2013 to 2017, will provide a combined lower cost impact than would occur where the cash method was continued to be used. The Company is hopeful that the use of the accrual method for both accounting and ratemaking purposes can be approved for fiscal periods 2013 and beyond, regardless of being in cost of service or an incentive regulation type of model.

b) Enbridge would look to file a Mercer Report at a minimum annually and at the most opportune time for estimating Pension costs when considering timing of relevant information issues.

Witnesses: K. Culbert
S. Chhelavda
S. Kancharla
A. Patel
B. Yuzwa

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: Ex. D1 /Tab 20/ Sch 1 / Table 1

With respect to the $13.5 million credit for Labour Capitalization, please explain the contents of the amount and how it is derived. Also, please identify and explain any amounts related to the Leave to Construct projects.

RESPONSE

The contents of the $13.5 million Labour Capitalization credit relate to account clearings for capital activities performed in departments such as Planning, Integrity, System Measurement, Training, and System Regulation. The amounts are derived by determining the percentage of department activities relating to capital projects, based on historical experience. While some of these amounts will likely be related to Leave to Construct projects, the exact amounts in that regard are not currently known.

Witnesses: J. Briggs
C. Hanlon
L. Lawler

BOARD STAFF INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: Ex. D1 /Tab 20/ Sch 1 / Table 2

Please provide a table showing the actual amounts for the period 2007 to 2013 in a similar format and detail level to Table 3. Provide explanations for any significant events.

RESPONSE

	2013 Budget	2012 Estimate	**2011 Actual**	**2010 Actual**	**2009 Actual**	**2008 Actual**	**2007 Actual**
Salaries and Wages	28,983	26,481	20,338	24,700	24,746	23,815	22,726
Labour Capitalization	(13,456)	(12,145)	(8,189)	(10,823)	(10,179)	(10,119)	(10,045)
Net Salaries and Wages	15,528	14,336	12,149	13,876	14,567	13,696	12,681
Materials & Supplies	820	866	1,462	2,254	2,588	2,364	2,074
Outside Services	21,541	18,795	16,255	14,399	19,133	18,167	17,714
Consulting	4,232	2,326	1,094	1,637	632	495	330
Fleet	568	556	406	5,730	5,443	6,578	6,064
Rents & Leases	1,764	1,858	2,338	1,475	4,409	5,425	5,924
Other	257	321	22	767	484	52	(236)
Internal Allocations and Recoveries	(5,997)	(5,674)	(4,031)	(12,020)	(12,589)	(14,485)	(13,144)
Total	38,713	33,384	29,695	28,120	34,667	32,291	31,406
FTE	366	345	277	355	369	367	362

Structural changes in the composition and responsibilities of the Pipeline Integrity & Safety Group have led to significant changes in departmental costs over the last seven years. From 2010 there have been changes relating to Facilities, Engineering, System Measurement, Fleet, and Purchasing, Distribution Logistics and Corrosion and Leak Survey departments which have impacted on the Pipeline Integrity & Safety Group. The table above reflects costs as they existed in the Pipeline Integrity & Safety Group in the year identified. The comparison of 2007 historical actual to 2013 budget by cost type at the overall Company level is a more consistent comparator as opposed to by

Witnesses: J. Briggs
C. Hanlon
L. Lawler

department as the overall cost type is relatively stable year over year. Please refer to the response to Board Staff Interrogatory #1 at Exhibit I, Issue D1, Tab 1, Schedule 1.

Set out below are explanations of some of the major variances in the Pipeline Integrity & Safety Group costs between 2008 and 2012.

(a) Significant events between 2008 actual and 2009 actual include the formation of the Technical Training group with costs of $1.3 million salaries, $0.2 million Consulting, and $0.3 million in Materials and Supplies.

(b) Significant events between 2009 actual and 2010 actual include the movement of the Facilities group out of Pipeline Integrity and Safety with a reduction in costs of $9.7 million in 2009. Category of spend for these costs is $2.0 million in Salaries, $5.3 million in Outside Services and $2.0 million for Rents and Leases and $0.4 million in Materials & Supplies. This reduction was offset by increased costs in 2010 of $0.9 million for Salaries and $1.0 million in Consulting and $0.3 million in Materials and Supplies relating to the Technical Training group.

(c) Significant events between 2010 and 2011 include the movement of the Fleet, Engineering, Purchasing, Distribution Logistics and System Measurement. This amounted to a reduction in Salaries, Materials and Supplies, and internal allocations and recoveries with Outside Services, offset by an increase of $2.2 million for Damage Prevention locating activities.

(d) Significant events between 2011 actual and 2012 estimate include increased Outside Service costs of $2.5 million primarily for increased In Line Inspection (ILI) and Damage Prevention activities and increased Consulting costs of $1.2 million relating to the Company's Path to Zero initiative. In addition, labour costs have increased, as outlined at Exhibit D1, Tab 20, Schedule 1, page 14.

Witnesses: J. Briggs
C. Hanlon
L. Lawler

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: Exhibit D1, Tab 20, Schedule 1

a) What is the salary and wage increase forecast for 2012 and 2013?

b) What is the impact on the revenue requirement of a 1% change in the salary and wage increase for both 2012 and 2013? Please provide the response for Salaries and Wages, Capitalization and Net Salaries and Wages, as defined in Tables 2 and 3.

RESPONSE

a) The net salary and wage increase forecast for 2012 is $2.190 million. The net salary and wage increase forecast for 2013 is $1.192 million.

b) Please refer to Energy Probe Interrogatory #5 at Exhibit I, Issue D1, Schedule 7.5 for the impact of a 1% change in salary and wage increase.

Witnesses: J. Briggs
C. Hanlon
L. Lawler

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: D1/20/1, p. 2

Please advise whether the $2.0 budget increment referred to is a one-time cost. If it is ongoing, please explain.

RESPONSE

The incremental cost referred to is ongoing in nature. However, it is associated with an In Line Inspection ("ILI") program that currently is specified to run every seven years. So the three pipelines referred to in the evidence will not be reinspected until approximately 2020, with the incremental cost associated with the ILI at that time expected to be higher than historical. It is anticipated that ILI technology will continue to evolve, and that EGD, as a prudent utility, will use new technologies on lines as the technologies become available. These technologies assist EGD to understand asset conditions of high stress pipelines.

Witnesses: J. Briggs
C. Hanlon
L. Lawler

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: D1/20/1, p. 4

Please provide the plan, business case, or other proposal document relating to the Path to Zero initiative. Please provide any reports providing information on the results of that initiative.

RESPONSE

In 2010 EGD worked with DuPont Sustainable Solutions ("DSS") to conduct an assessment of the present state of the safety culture. Based on the results of this assessment, a project team was formulated and led by DSS to identify the areas of improvement. Please see attached DSS Safety Culture Initiative dated July 21, 2011. Furthermore, DSS and EGD conducted a safety perception survey at the end of 2011. Results indicated the following safety strengths:

- Presence of safety values,
- The extent to which safety rules are followed,
- Safety meeting attendance,
- Thoroughness of investigation of injuries and incidents, and
- Rating of the safety of facilities and equipment.

Also, the survey indicated a number of opportunities for improvement:

- Recognition of safety achievements,
- The presence of off-the-job safety programs,
- Involvement in safety activities,
- Extent of involvements in safety audits, and
- Belief that injuries can be prevented.

Witnesses: J. Briggs
C. Hanlon
L. Lawler

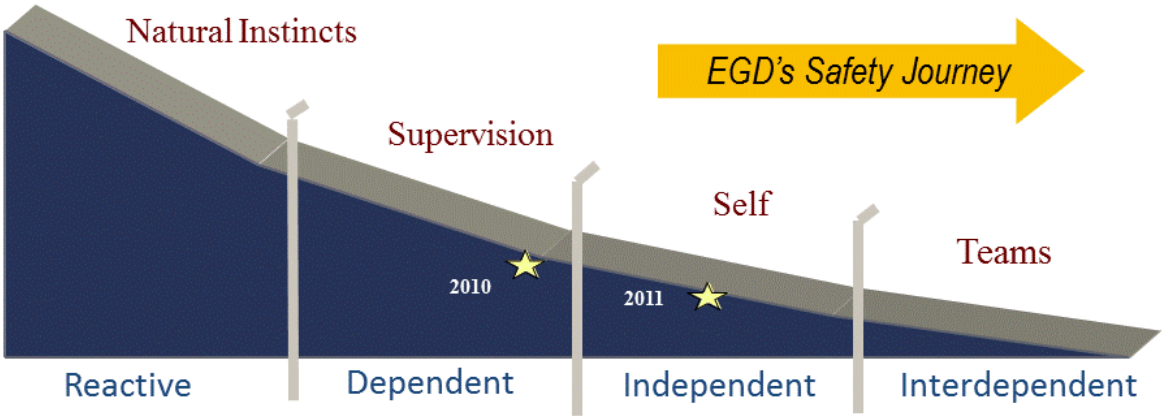
DSS utilizes The Bradley Curve to measure the safety culture strength of an organization. The Bradley Curve was developed at DuPont in the mid 1990's when their CEO commissioned a discovery team to look at the culture in several DuPont sites to understand basic differences that were impacting the safety performance. The aim was to help define the path that DuPont could take to achieve ZERO injuries. In general, it shows characteristics of an organization as it moves from external control motivation to internal motivation. The belief based on looking at the various plants performance and at the safety cultures at those plants was that ultimately, cultures that evolved more towards internal motivation were able to achieve and sustain better levels of safety performance.

The words at the bottom of the Bradley Curve are observable characteristics or statements of organizational values and can be used to determine where an organization ‘measures up’. The vertical axis is a subjective assessment of safety performance - lower is better and is symbolic of lower injuries. Obviously, the curve itself is divided into four regions and given the names "Reactive, Dependent, Independent and Interdependent," to try to capture conceptually how the organization functions. Assessment data from interviews, surveys and reviews of management processes and systems is considered in order to characterize where an organization fits on the curve.

Below is a graphical illustration of EGD’s relative culture strength from the original assessment in 2010 to a perception survey conducted in 2011. EGD has moved from the dependent to the independent phase, with the ultimate goal of achieving interdependency.

Current State at Enbridge

DuPont's assessment places EGD's safety culture approaching the "Independent" phase



- Safety by natural instinct
- Delegated to Safety Manager
- Compliance is the goal
- Lack of management involvement

- Training
- Condition of Employment
- Fear/Discipline
- Value all people
- Rules and Procedures
- Management Commitment
- Supervisor Control

- Personal Knowledge
- Internalization
- Personal value
- Care for self
- Practice, habits
- Increased communication
- Individual recognition

- Help other conform
- Others' Keeper
- Networking Contributor
- Care for others
- Organizational pride
- Open communications

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Witnesses: J. Briggs
C. Hanlon
L. Lawler

DuPont Sustainable Solutions

Enbridge Gas Distribution
Safety Culture Initiative

Enbridge Gas Distribution

July 21, 2011

1 Introduction

1.1 Background

In 2010, Enbridge contracted with DuPont to benchmark Enbridge's health and safety management system against DuPont's internal standard. The assessment provided several recommendations to improve Enbridge's safety and health management system performance, addressing key areas of leadership, structure and process.

As a follow-up, Enbridge requested Dupont assist in developing a strategic initiative to address the recommendations from the safety assessment. The effort would include assisting with articulating Enbridge leadership's vision for safety in the organization, developing an appropriate governance structure, and establishing a schedule for executing process improvement teams and local implementation assistance.

This exhibit contains the project schedule technical scope, and work products that form the basis for Enbridge Gas Distribution (EGD) Initiative. The plan was developed collaboratively with EGD project team.

1.2 Approach/Methodology

A project team was chartered by the Executive Management Team to develop a strategic implementation plan for the Safety Improvement Project aimed at the development/strengthening of key process safety and employee safety management structures and safety processes. The 14-member team brought together expertise from Operations, Engineering, Safety Facilities and Human Resources to develop a core understanding of the opportunities for improvement from the 2010 Safety Assessment

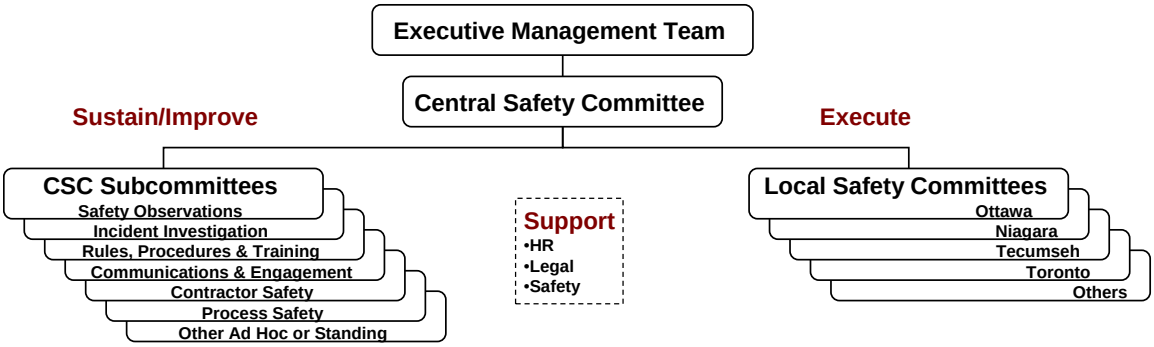
Following introduction to DuPont safety management approach, the project team conducted a review of DuPont's benchmarks in four key processes: Safety Observations; Incident Investigations; Rules, Procedures & Training; and Communications and Engagement. The benchmark included establishing a vision of the future state and potential barriers to achieving the future state. The future state worksheets are provided in Appendix A: Employee Safety Process Future State Worksheets.

In addition to specific safety processes, the team looked at DuPont's governance model and developed a structure that would enhance line management accountability and improve the flow of communication up and down the organization (see Figure 1: Safety Governance Structure). The structure requires the establishment of a new permanent safety governance structure that will be responsible for managing all aspects of safety at EGD, reporting to the Executive Management Team.

To provide specific focus to key safety processes, teams will be established with specific responsibility to update and sustain these processes. Draft charters were developed for each process team (see Appendices B-E).

In addition, a local safety committee, established at the general manager/director level, will assist with execution of specific safety process changes and will be held accountable for success of these processes. The initial assignment of these local safety committees was tied to the existence of the current Joint Environment, Health and Safety Committees (JEHSC). The expectation was that the leadership of JEHSC would be members of the Local Safety Committees in the regions, enhancing their ability to bring issues to resolution.

Figure 1: Safety Governance Structure



The start-up of the various teams will be staggered to ensure there are sufficient resources to support the work effort.

A second team was established to review the applicability of DuPont's process safety management system (PSM) and performance of EGDs Distribution Management System (DMS). The team was introduced to process safety management and mapped the current DMS design to DuPont's process safety elements (Figure 2). The intent of process safety is to help drive improved risk management throughout key processes in EGD. The team defined these key processes as the physical movement of gas from storage or suppliers to EGDs customers.

Figure 2: DMS-PSM Mapping

	Life Cycle Functions										
PSM Elements	Analysis & Design	Construction	Material Evaluation & Procurement	Integrity Management	Surveys & Inspections	Utility Customer Service	Distribution Maintenance	Operations Administration	Damage Prevention	Emergency Response	Health & Safety
PSM Governance	X	X	X	X	X	X	X	X	X	X	X
Process Safety Information				X					X		
Process Hazards Analysis	X	X		X				X	X		
Management of Change - Technology	X	X	X					X			
Management of Change - Facilities	X	X	X								
Management of Change - Personnel				X				X		X	
Emergency Response										X	
Quality Assurance	X		X				X				
Mechanical Integrity			X	X	X		X				
Pre-Startup Safety Reviews		X					X	X			X
Contractor Safety		X						X		X	X
Incident Investigation		X						X	X		X
Procedures							X	X	X	X	
Training & Performance							X	X		X	
Auditing			X	X	X	X	X	X	X	X	

Using this definition of *process* and looking at DMS through the PSM element lens, the team identified several key learnings:

1. DMS needed to be expanded beyond distribution to include other facilities (storage, gate stations, etc.).
2. Some elements of the current DMS structure were not *process* safety-related and should be removed.
3. DMS' current governance model was designed around individual processes owners which was rather unwieldy to maintain; however, there was significant potential to improve governance by organizing around the already defined life-cycle functions. As shown in Figure 2, there is good alignment between PSM elements and DMS life-cycle functions.

As before, the benchmark included establishing a vision of the future state and potential barriers to achieving the future state. The future state worksheets are provided in Appendix F: Process Safety Management Future State Worksheets.

The governance structure provided in Figure 1 is equally suited to manage both employee safety and process safety. A project plan was developed to address gaps in the current DMS design and to build up a sustainable governance model. The project plan attempts to balance EGDs efforts between expanding the scope of the current system and adding new elements to DMS (e.g., process hazards analysis).

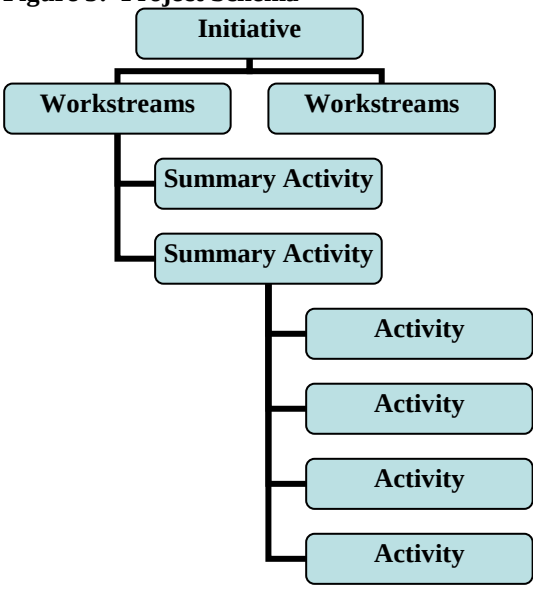
As part of the change, the team felt it was important to modify the brand of DMS to highlight its singular focus on safety processes. The new title that is used throughout the project plan is Distribution Safety Systems (DSS).

2 Project Design/Approach

2.1 Project Schema

The project was designed around the schema in Figure 3: Project Schema. A work breakdown structure is provided in the next section, showing project scope down to the workstream level. The detailed Gantt chart is provided in the subsequent section, followed by the implementation plan descriptions.

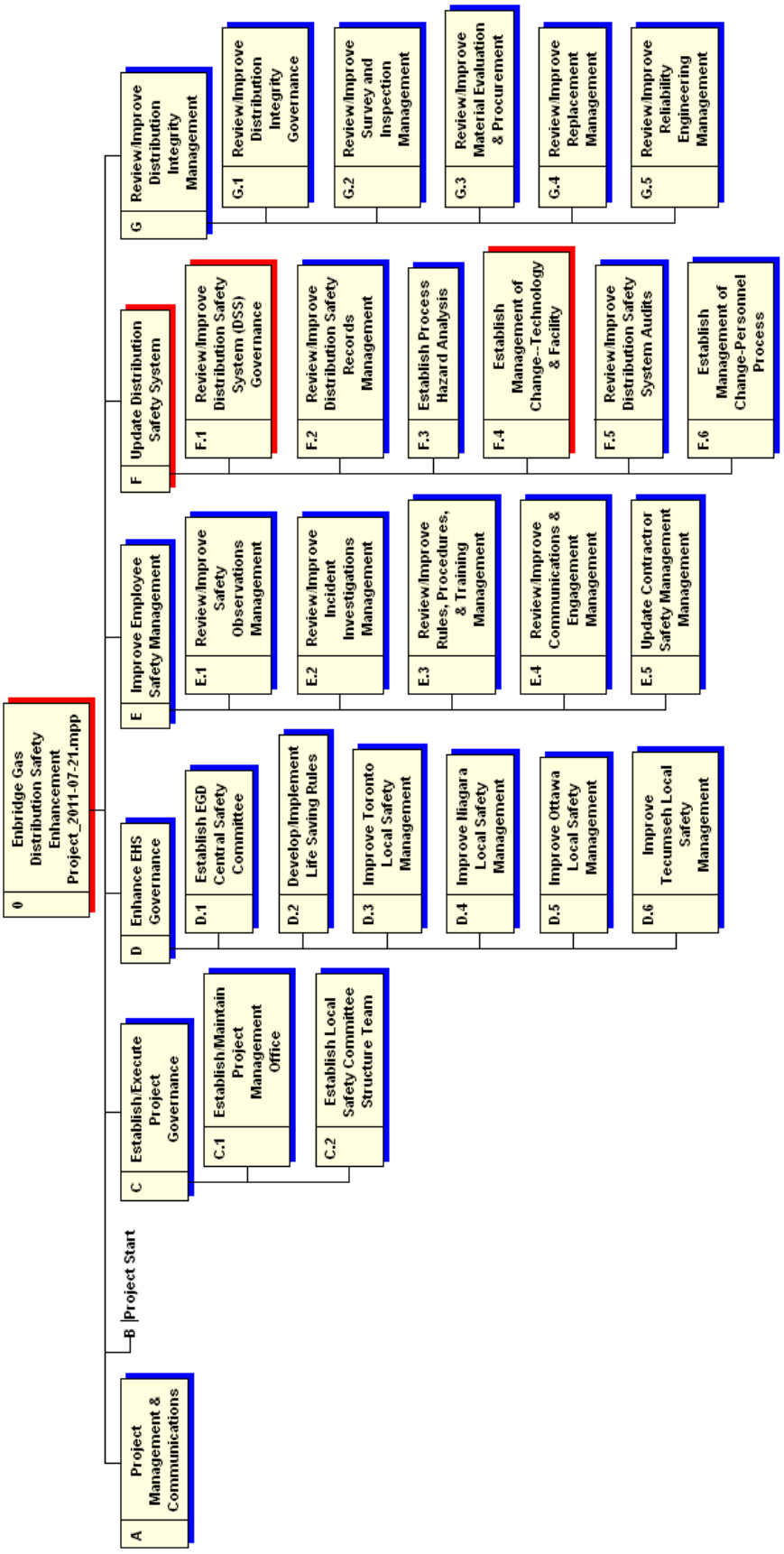
Figure 3: Project Schema



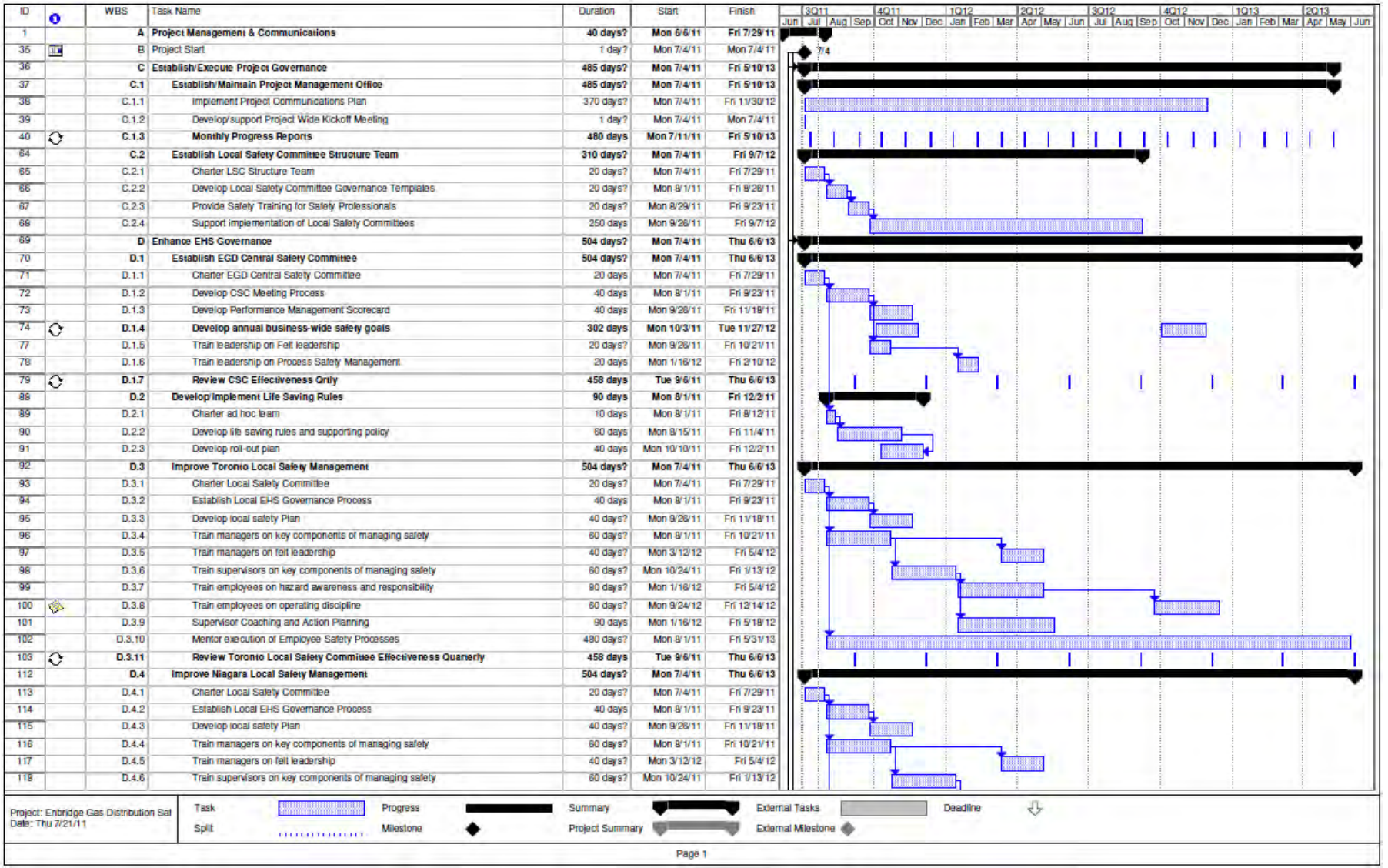
Examples:

1. Workstreams:
    a. Enhance Employee Safety Governance
    b. Enhance PSM Governance
2. Summary Activities:
    a. Establish Central Safety Committee (CSC)
    b. Develop CSC process/content
3. Activities:
    a. Id Chair person
    b. Id membership
    c. Develop understanding of CSC function
    d. Develop/approve charter

2.2 *Work Breakdown Structure*



2.3 Schedule



ID	WBS	Task Name	Duration	Start	Finish
1	A	**Project Management & Communications**	**40 days?**	**Mon 6/6/11**	**Fri 7/29/11**
35	B	Project Start	1 day?	Mon 7/4/11	Mon 7/4/11
36	C	**Establish/Execute Project Governance**	**485 days?**	**Mon 7/4/11**	**Fri 5/10/13**
37	C.1	**Establish/Mainain Project Management Office**	**485 days?**	**Mon 7/4/11**	**Fri 5/10/13**
38	C.1.1	Implement Project Communications Plan	370 days?	Mon 7/4/11	Fri 11/30/12
39	C.1.2	Develop/support Project Wide Kickoff Meeting	1 day?	Mon 7/4/11	Mon 7/4/11
40	C.1.3	**Monthly Progress Reports**	**480 days**	**Mon 7/11/11**	**Fri 5/10/13**
64	C.2	**Establish Local Safety Committee Structure Team**	**310 days?**	**Mon 7/4/11**	**Fri 9/7/12**
65	C.2.1	Charter LSC Structure Team	20 days?	Mon 7/4/11	Fri 7/29/11
66	C.2.2	Develop Local Safety Committee Governance Templates	20 days?	Mon 8/1/11	Fri 8/26/11
67	C.2.3	Provide Safety Training for Safety Professionals	20 days?	Mon 8/29/11	Fri 9/23/11
68	C.2.4	Support implementation of Local Safety Committees	250 days	Mon 9/26/11	Fri 9/7/12
69	D	**Enhance EHS Governance**	**504 days?**	**Mon 7/4/11**	**Thu 6/6/13**
70	D.1	**Establish EGD Central Safety Committee**	**504 days?**	**Mon 7/4/11**	**Thu 6/6/13**
71	D.1.1	Charter EGD Central Safety Committee	20 days	Mon 7/4/11	Fri 7/29/11
72	D.1.2	Develop CSC Meeting Process	40 days	Mon 8/1/11	Fri 9/23/11
73	D.1.3	Develop Performance Management Scorecard	40 days	Mon 9/26/11	Fri 11/18/11
74	D.1.4	**Develop annual business-wide safety goals**	**302 days**	**Mon 10/3/11**	**Tue 11/27/12**
77	D.1.5	Train leadership on Felt leadership	20 days?	Mon 9/26/11	Fri 10/21/11
78	D.1.6	Train leadership on Process Safety Management	20 days	Mon 1/16/12	Fri 2/10/12
79	D.1.7	**Review CSC Effectiveness Qrtly**	**458 days**	**Tue 9/6/11**	**Thu 6/6/13**
88	D.2	**Develop/Implement Life Saving Rules**	**90 days**	**Mon 8/1/11**	**Fri 12/2/11**
89	D.2.1	Charter ad hoc team	10 days	Mon 8/1/11	Fri 8/12/11
90	D.2.2	Develop life saving rules and supporting policy	60 days	Mon 8/15/11	Fri 11/4/11
91	D.2.3	Develop roll-out plan	40 days	Mon 10/10/11	Fri 12/2/11
92	D.3	**Improve Toronto Local Safety Management**	**504 days?**	**Mon 7/4/11**	**Thu 6/6/13**
93	D.3.1	Charter Local Safety Committee	20 days?	Mon 7/4/11	Fri 7/29/11
94	D.3.2	Establish Local EHS Governance Process	40 days	Mon 8/1/11	Fri 9/23/11
95	D.3.3	Develop local safety Plan	40 days?	Mon 9/26/11	Fri 11/18/11
96	D.3.4	Train managers on key components of managing safety	60 days?	Mon 8/1/11	Fri 10/21/11
97	D.3.5	Train managers on felt leadership	40 days?	Mon 3/12/12	Fri 5/4/12
98	D.3.6	Train supervisors on key components of managing safety	60 days?	Mon 10/24/11	Fri 1/13/12
99	D.3.7	Train employees on hazard awareness and responsibility	90 days?	Mon 1/16/12	Fri 5/4/12
100	D.3.8	Train employees on operating discipline	60 days?	Mon 9/24/12	Fri 12/14/12
101	D.3.9	Supervisor Coaching and Action Planning	90 days	Mon 1/16/12	Fri 5/18/12
102	D.3.10	Mentor execution of Employee Safety Processes	480 days?	Mon 8/1/11	Fri 5/31/13
103	D.3.11	**Review Toronto Local Safety Committee Effectiveness Quarterly**	**458 days**	**Tue 9/6/11**	**Thu 6/6/13**
112	D.4	**Improve Niagara Local Safety Management**	**504 days?**	**Mon 7/4/11**	**Thu 6/6/13**
113	D.4.1	Charter Local Safety Committee	20 days?	Mon 7/4/11	Fri 7/29/11
114	D.4.2	Establish Local EHS Governance Process	40 days	Mon 8/1/11	Fri 9/23/11
115	D.4.3	Develop local safety Plan	40 days?	Mon 9/26/11	Fri 11/18/11
116	D.4.4	Train managers on key components of managing safety	60 days?	Mon 8/1/11	Fri 10/21/11
117	D.4.5	Train managers on felt leadership	40 days?	Mon 3/12/12	Fri 5/4/12
118	D.4.6	Train supervisors on key components of managing safety	60 days?	Mon 10/24/11	Fri 1/13/12

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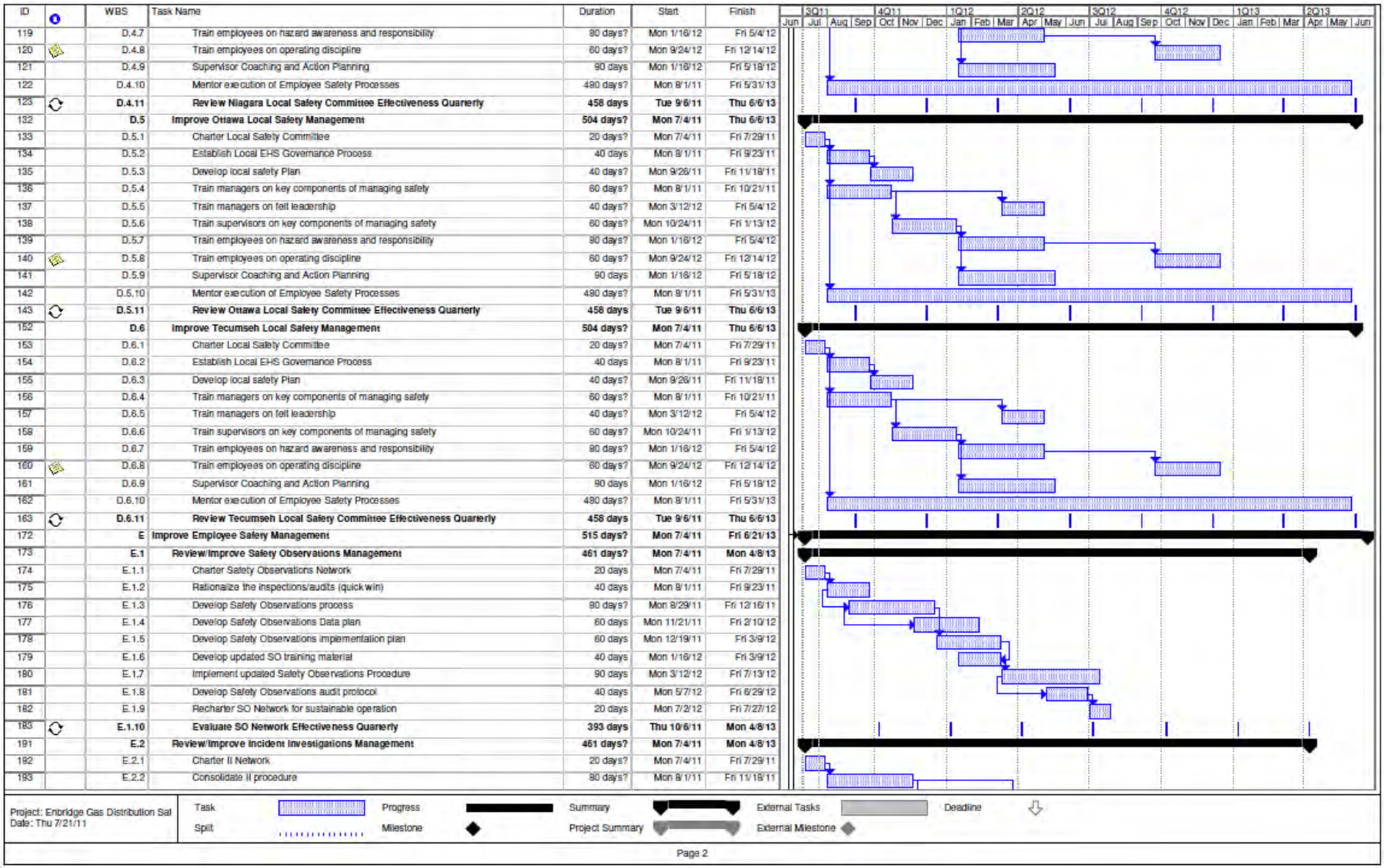

ID	WBS	Task Name	Duration	Start	Finish
119	D.4.7	Train employees on hazard awareness and responsibility	90 days?	Mon 1/16/12	Fri 5/4/12
120	D.4.8	Train employees on operating discipline	60 days?	Mon 9/24/12	Fri 12/14/12
121	D.4.9	Supervisor Coaching and Action Planning	90 days	Mon 1/16/12	Fri 5/18/12
122	D.4.10	Mentor execution of Employee Safety Processes	480 days?	Mon 8/1/11	Fri 5/31/13
123	**D.4.11**	**Review Niagara Local Safety Committee Effectiveness Quarterly**	**458 days**	**Tue 9/6/11**	**Thu 6/6/13**
132	**D.5**	**Improve Ottawa Local Safety Management**	**504 days?**	**Mon 7/4/11**	**Thu 6/6/13**
133	D.5.1	Charter Local Safety Committee	20 days?	Mon 7/4/11	Fri 7/29/11
134	D.5.2	Establish Local EHS Governance Process	40 days	Mon 8/1/11	Fri 9/23/11
135	D.5.3	Develop local safety Plan	40 days?	Mon 9/26/11	Fri 11/18/11
136	D.5.4	Train managers on key components of managing safety	60 days?	Mon 8/1/11	Fri 10/21/11
137	D.5.5	Train managers on felt leadership	40 days?	Mon 3/12/12	Fri 5/4/12
138	D.5.6	Train supervisors on key components of managing safety	60 days?	Mon 10/24/11	Fri 1/13/12
139	D.5.7	Train employees on hazard awareness and responsibility	90 days?	Mon 1/16/12	Fri 5/4/12
140	D.5.8	Train employees on operating discipline	60 days?	Mon 9/24/12	Fri 12/14/12
141	D.5.9	Supervisor Coaching and Action Planning	90 days	Mon 1/16/12	Fri 5/18/12
142	D.5.10	Mentor execution of Employee Safety Processes	480 days?	Mon 8/1/11	Fri 5/31/13
143	**D.5.11**	**Review Ottawa Local Safety Committee Effectiveness Quarterly**	**458 days**	**Tue 9/6/11**	**Thu 6/6/13**
152	**D.6**	**Improve Tecumseh Local Safety Management**	**504 days?**	**Mon 7/4/11**	**Thu 6/6/13**
153	D.6.1	Charter Local Safety Committee	20 days?	Mon 7/4/11	Fri 7/29/11
154	D.6.2	Establish Local EHS Governance Process	40 days	Mon 8/1/11	Fri 9/23/11
155	D.6.3	Develop local safety Plan	40 days?	Mon 9/26/11	Fri 11/18/11
156	D.6.4	Train managers on key components of managing safety	60 days?	Mon 8/1/11	Fri 10/21/11
157	D.6.5	Train managers on felt leadership	40 days?	Mon 3/12/12	Fri 5/4/12
158	D.6.6	Train supervisors on key components of managing safety	60 days?	Mon 10/24/11	Fri 1/13/12
159	D.6.7	Train employees on hazard awareness and responsibility	90 days?	Mon 1/16/12	Fri 5/4/12
160	D.6.8	Train employees on operating discipline	60 days?	Mon 9/24/12	Fri 12/14/12
161	D.6.9	Supervisor Coaching and Action Planning	90 days	Mon 1/16/12	Fri 5/18/12
162	D.6.10	Mentor execution of Employee Safety Processes	480 days?	Mon 8/1/11	Fri 5/31/13
163	**D.6.11**	**Review Tecumseh Local Safety Committee Effectiveness Quarterly**	**458 days**	**Tue 9/6/11**	**Thu 6/6/13**
172	**E**	**Improve Employee Safety Management**	**515 days?**	**Mon 7/4/11**	**Fri 6/21/13**
173	**E.1**	**Review/Improve Safety Observations Management**	**461 days?**	**Mon 7/4/11**	**Mon 4/8/13**
174	E.1.1	Charter Safety Observations Network	20 days	Mon 7/4/11	Fri 7/29/11
175	E.1.2	Rationalize the inspections/audits (quick win)	40 days	Mon 8/1/11	Fri 9/23/11
176	E.1.3	Develop Safety Observations process	90 days?	Mon 8/29/11	Fri 12/16/11
177	E.1.4	Develop Safety Observations Data plan	60 days	Mon 11/21/11	Fri 2/10/12
178	E.1.5	Develop Safety Observations implementation plan	60 days	Mon 12/19/11	Fri 3/9/12
179	E.1.6	Develop updated SO training material	40 days	Mon 1/16/12	Fri 3/9/12
180	E.1.7	Implement updated Safety Observations Procedure	90 days	Mon 3/12/12	Fri 7/13/12
181	E.1.8	Develop Safety Observations audit protocol	40 days	Mon 5/7/12	Fri 6/29/12
182	E.1.9	Recharter SO Network for sustainable operation	20 days	Mon 7/2/12	Fri 7/27/12
183	**E.1.10**	**Evaluate SO Network Effectiveness Quarterly**	**393 days**	**Thu 10/6/11**	**Mon 4/8/13**
191	**E.2**	**Review/Improve Incident Investigations Management**	**461 days?**	**Mon 7/4/11**	**Mon 4/8/13**
192	E.2.1	Charter II Network	20 days?	Mon 7/4/11	Fri 7/29/11
193	E.2.2	Consolidate II procedure	90 days?	Mon 8/1/11	Fri 11/18/11

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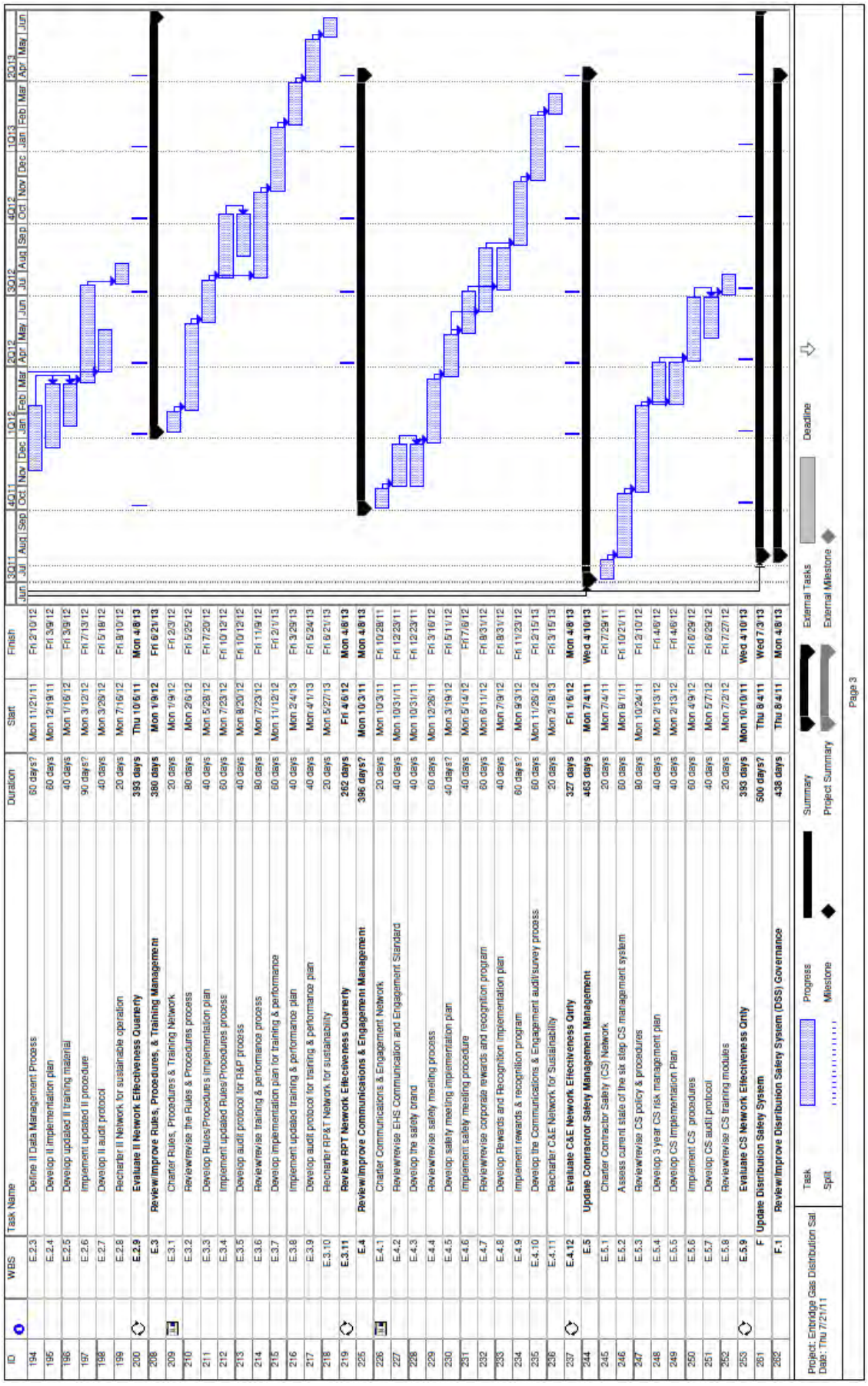
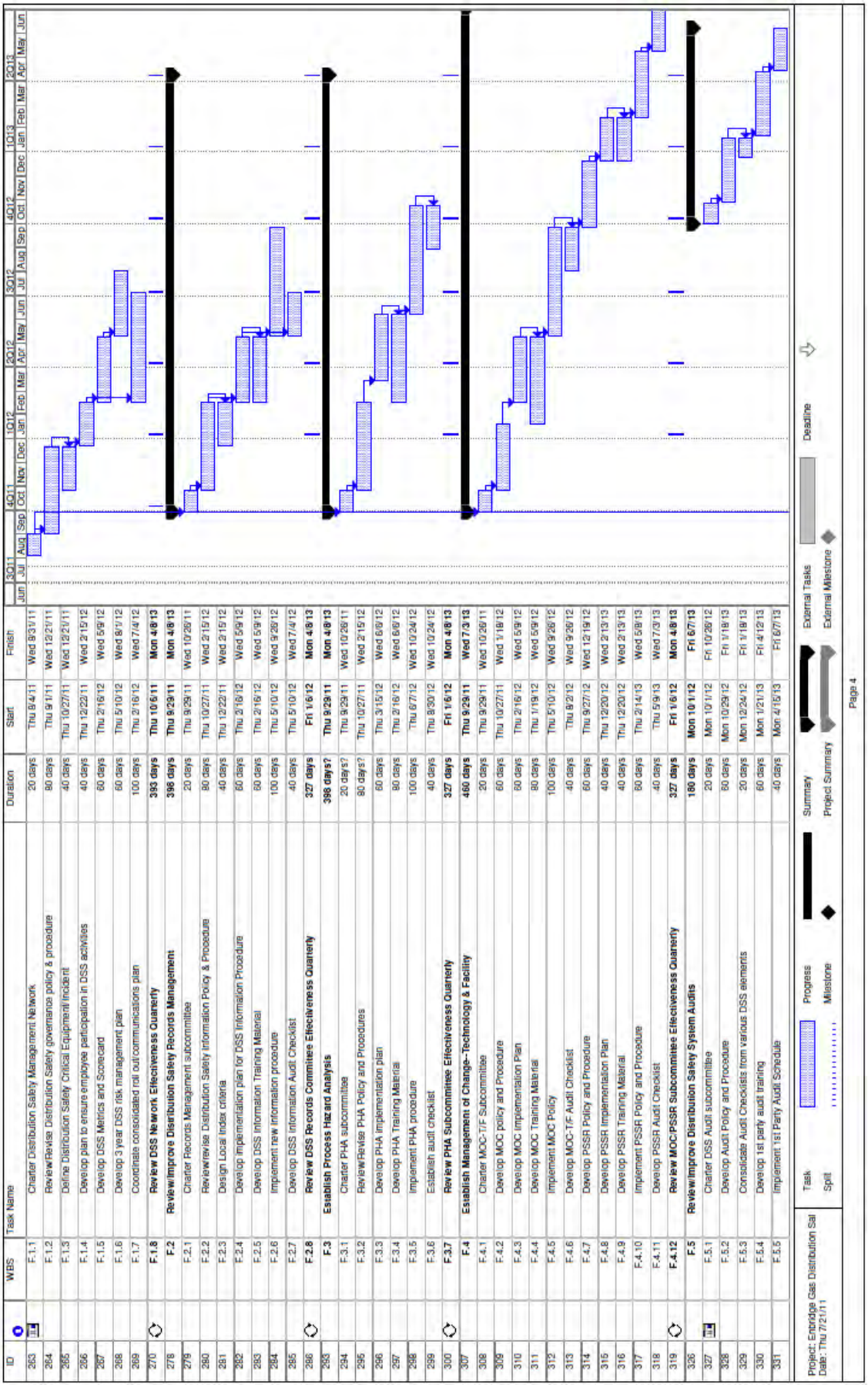


ID	WBS	Task Name	Duration	Start	Finish
194	E.2.3	Define II Data Management Process	60 days?	Mon 11/21/11	Fri 2/10/12
195	E.2.4	Develop II implementation plan	60 days	Mon 12/19/11	Fri 3/9/12
196	E.2.5	Develop updated II training material	40 days	Mon 1/16/12	Fri 3/9/12
197	E.2.6	Implement updated II procedure	90 days?	Mon 3/12/12	Fri 7/13/12
198	E.2.7	Develop II audit protocol	40 days	Mon 3/26/12	Fri 5/18/12
199	E.2.8	Recharter II Network for sustainable operation	20 days	Mon 7/16/12	Fri 8/10/12
200	**E.2.9**	**Evaluate II Network Effectiveness Quarterly**	**393 days**	**Thu 10/6/11**	**Mon 4/8/13**
208	**E.3**	**Review/Improve Rules, Procedures, & Training Management**	**380 days**	**Mon 1/9/12**	**Fri 6/21/13**
209	E.3.1	Charter Rules, Procedures & Training Network	20 days	Mon 1/9/12	Fri 2/3/12
210	E.3.2	Review/revise the Rules & Procedures process	80 days	Mon 2/6/12	Fri 5/25/12
211	E.3.3	Develop Rules/Procedures implementation plan	40 days	Mon 5/28/12	Fri 7/20/12
212	E.3.4	Implement updated Rules/Procedures process	60 days	Mon 7/23/12	Fri 10/12/12
213	E.3.5	Develop audit protocol for R&P process	40 days	Mon 8/20/12	Fri 10/12/12
214	E.3.6	Review/revise training & performance process	80 days	Mon 7/23/12	Fri 11/9/12
215	E.3.7	Develop implementation plan for training & performance	60 days	Mon 11/12/12	Fri 2/1/13
216	E.3.8	Implement updated training & performance plan	40 days	Mon 2/4/13	Fri 3/29/13
217	E.3.9	Develop audit protocol for training & performance plan	40 days	Mon 4/1/13	Fri 5/24/13
218	E.3.10	Recharter R,P&T Network for sustainability	20 days	Mon 5/27/13	Fri 6/21/13
219	**E.3.11**	**Review RPT Network Effectiveness Quarterly**	**262 days**	**Fri 4/6/12**	**Mon 4/8/13**
225	**E.4**	**Review/Improve Communications & Engagement Management**	**396 days?**	**Mon 10/3/11**	**Mon 4/8/13**
226	E.4.1	Charter Communications & Engagement Network	20 days	Mon 10/3/11	Fri 10/28/11
227	E.4.2	Review/revise EHS Communication and Engagement Standard	40 days	Mon 10/31/11	Fri 12/23/11
228	E.4.3	Develop the safety brand	40 days	Mon 10/31/11	Fri 12/23/11
229	E.4.4	Review/revise safety meeting process	60 days	Mon 12/26/11	Fri 3/16/12
230	E.4.5	Develop safety meeting implementation plan	40 days?	Mon 3/19/12	Fri 5/11/12
231	E.4.6	Implement safety meeting procedure	40 days	Mon 5/14/12	Fri 7/6/12
232	E.4.7	Review/revise corporate rewards and recognition program	60 days	Mon 6/11/12	Fri 8/31/12
233	E.4.8	Develop Rewards and Recognition implementation plan	40 days	Mon 7/9/12	Fri 8/31/12
234	E.4.9	Implement rewards & recognition program	60 days?	Mon 9/3/12	Fri 11/23/12
235	E.4.10	Develop the Communications & Engagement audit/survey process	60 days	Mon 11/26/12	Fri 2/15/13
236	E.4.11	Recharter C&E Network for Sustainability	20 days	Mon 2/18/13	Fri 3/15/13
237	**E.4.12**	**Evaluate C&E Network Effectiveness Qrtly**	**327 days**	**Fri 1/6/12**	**Mon 4/8/13**
244	**E.5**	**Update Contractor Safety Management Management**	**453 days**	**Mon 7/4/11**	**Wed 4/10/13**
245	E.5.1	Charter Contractor Safety (CS) Network	20 days	Mon 7/4/11	Fri 7/29/11
246	E.5.2	Assess current state of the six step CS management system	60 days	Mon 8/1/11	Fri 10/21/11
247	E.5.3	Review/revise CS policy & procedures	80 days	Mon 10/24/11	Fri 2/10/12
248	E.5.4	Develop 3 year CS risk management plan	40 days	Mon 2/13/12	Fri 4/6/12
249	E.5.5	Develop CS implementation Plan	40 days	Mon 2/13/12	Fri 4/6/12
250	E.5.6	Implement CS procedures	60 days	Mon 4/9/12	Fri 6/29/12
251	E.5.7	Develop CS audit protocol	40 days	Mon 5/7/12	Fri 6/29/12
252	E.5.8	Review/revise CS training modules	20 days	Mon 7/2/12	Fri 7/27/12
253	**E.5.9**	**Evaluate CS Network Effectiveness Qrtly**	**393 days**	**Mon 10/10/11**	**Wed 4/10/13**
261	**F**	**Update Distribution Safety System**	**500 days?**	**Thu 8/4/11**	**Wed 7/3/13**
262	**F.1**	**Review/Improve Distribution Safety System (DSS) Governance**	**438 days**	**Thu 8/4/11**	**Mon 4/8/13**


ID
WBS
Task Name
Duration
Start
Finish
F.1.1 Charter Distribution Safety Management Network 20 days Thu 8/4/11 Wed 8/31/11
F.1.2 Review/Revise Distribution Safety governance policy & procedure 80 days Thu 9/1/11 Wed 12/21/11
F.1.3 Define Distribution Safety Critical Equipment/ Incident 40 days Thu 10/27/11 Wed 12/21/11
F.1.4 Develop plan to ensure employee participation in DSS activities 40 days Thu 12/22/11 Wed 2/15/12
F.1.5 Develop DSS Metrics and Scorecard 60 days Thu 2/16/12 Wed 5/9/12
F.1.6 Develop 3 year DSS risk management plan 60 days Thu 5/10/12 Wed 8/1/12
F.1.7 Coordinate consolidated rail out communications plan 100 days Thu 2/16/12 Wed 7/4/12
F.1.8 Review DSS Network Effectiveness Quarterly 393 days Thu 10/6/11 Mon 4/8/13
F.2 Review/Improve Distribution Safety Records Management 396 days Thu 9/29/11 Mon 4/8/13
F.2.1 Charter Records Management subcommittee 20 days Thu 9/29/11 Wed 10/26/11
F.2.2 Review/revise Distribution Safety Information Policy & Procedure 80 days Thu 10/27/11 Wed 2/15/12
F.2.3 Design Local Index criteria 40 days Thu 12/22/11 Wed 2/15/12
F.2.4 Develop implementation plan for DSS Information Procedure 60 days Thu 2/16/12 Wed 5/9/12
F.2.5 Develop DSS Information Training Material 60 days Thu 2/16/12 Wed 5/9/12
F.2.6 Implement new information procedure 100 days Thu 5/10/12 Wed 9/26/12
F.2.7 Develop DSS Information Audit Checklist 40 days Thu 5/10/12 Wed 7/4/12
F.2.8 Review DSS Records Commitee Effectiveness Quarterly 327 days Fri 1/6/12 Mon 4/8/13
F.3 Establish Process Hazard Analysis 396 days? Thu 9/29/11 Mon 4/8/13
F.3.1 Charter PHA subcommittee 20 days? Thu 9/29/11 Wed 10/26/11
F.3.2 Review/Revise PHA Policy and Procedures 80 days? Thu 10/27/11 Wed 2/15/12
F.3.3 Develop PHA implementation plan 60 days Thu 3/15/12 Wed 6/6/12
F.3.4 Develop PHA Training Material 80 days Thu 2/16/12 Wed 6/6/12
F.3.5 Implement PHA procedure 100 days Thu 6/7/12 Wed 10/24/12
F.3.6 Establish audit checklist 40 days Thu 8/30/12 Wed 10/24/12
F.3.7 Review PHA Subcommittee Effectiveness Quarterly 327 days Fri 1/6/12 Mon 4/8/13
F.4 Establish Management of Change--Technology & Facility 460 days Thu 9/29/11 Wed 7/3/13
F.4.1 Charter MOC-T/F Subcommittee 20 days Thu 9/29/11 Wed 10/26/11
F.4.2 Develop MOC policy and Procedure 60 days Thu 10/27/11 Wed 1/18/12
F.4.3 Develop MOC implementation Plan 60 days Thu 2/16/12 Wed 5/9/12
F.4.4 Develop MOC Training Material 80 days Thu 1/19/12 Wed 5/9/12
F.4.5 Implement MOC Policy 100 days Thu 5/10/12 Wed 9/26/12
F.4.6 Develop MOC-T/F Audit Checklist 40 days Thu 8/2/12 Wed 9/26/12
F.4.7 Develop PSSR Policy and Procedure 60 days Thu 9/27/12 Wed 12/19/12
F.4.8 Develop PSSR Implementation Plan 40 days Thu 12/20/12 Wed 2/13/13
F.4.9 Develop PSSR Training Material 40 days Thu 12/20/12 Wed 2/13/13
F.4.10 Implement PSSR Policy and Procedure 60 days Thu 2/14/13 Wed 5/8/13
F.4.11 Develop PSSR Audit Checklist 40 days Thu 5/9/13 Wed 7/3/13
F.4.12 Review MOC/PSSR Subcommittee Effectiveness Quarterly 327 days Fri 1/6/12 Mon 4/8/13
F.5 Review/Improve Distribution Safety System Audits 180 days Mon 10/1/12 Fri 6/7/13
F.5.1 Charter DSS Audit subcommittee 20 days Mon 10/1/12 Fri 10/26/12
F.5.2 Develop Audit Policy and Procedure 80 days Mon 10/29/12 Fri 1/18/13
F.5.3 Consolidate Audit Checklists from various DSS elements 20 days Mon 12/24/12 Fri 1/18/13
F.5.4 Develop 1st party audit training 60 days Mon 1/21/13 Fri 4/12/13
F.5.5 Implement 1st Party Audit Schedule 40 days Mon 4/15/13 Fri 6/7/13
3Q11
4Q11
1Q12
2Q12
3Q12
4Q12
1Q13
2013
Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun
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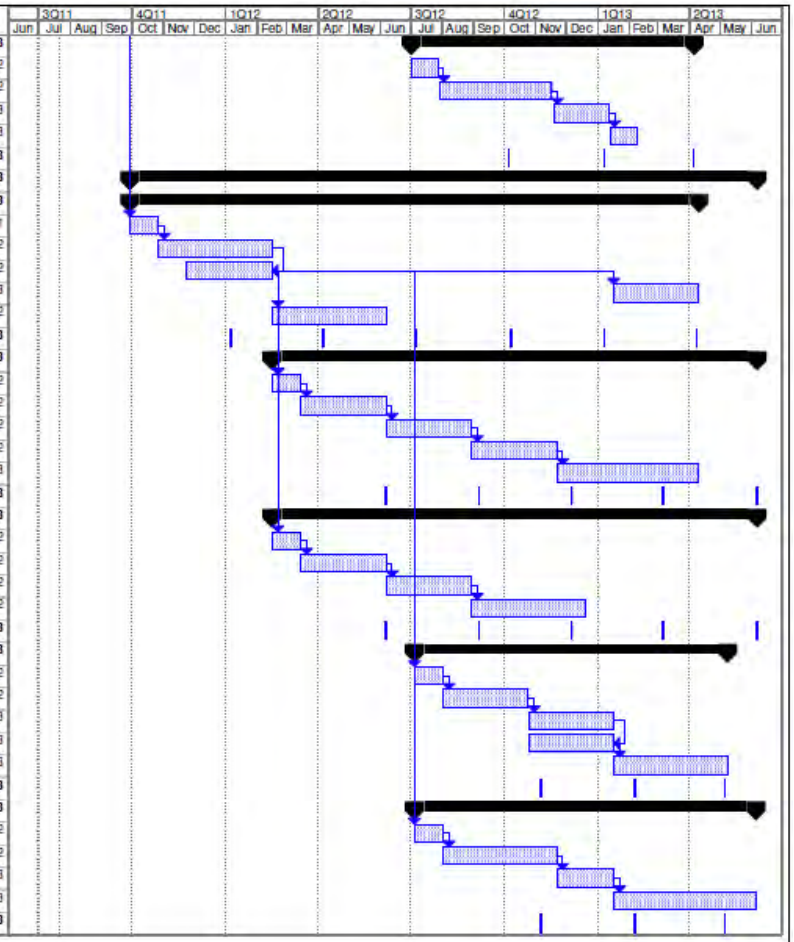
ID	WBS	Task Name	Duration	Start	Finish
332	F.6	**Establish Management of Change-Personnel Process**	**200 days**	**Mon 7/2/12**	**Fri 4/5/13**
333	F.6.1	Charter MOC-P Subcommittee	20 days	Mon 7/2/12	Fri 7/27/12
334	F.6.2	Develop MOC-P Policy and Procedure	80 days	Mon 7/30/12	Fri 11/16/12
335	F.6.3	Develop Implementation Plan	40 days	Mon 11/19/12	Fri 1/11/13
336	F.6.4	Develop MOC-P Audit Checklist	20 days	Mon 1/14/13	Fri 2/8/13
337	F.6.5	**Review MOC-P Subcommittee Effectiveness Quarterly**	**131 days**	**Fri 10/5/12**	**Fri 4/5/13**
341	G	**Review/Improve Distribution Integrity Management**	**441 days?**	**Thu 9/29/11**	**Thu 6/6/13**
342	G.1	**Review/Improve Distribution Integrity Governance**	**400 days?**	**Thu 9/29/11**	**Wed 4/10/13**
343	G.1.1	Charter Distribution Integrity Subcommittee	20 days	Thu 9/29/11	Wed 10/26/11
344	G.1.2	Develop Distribution System Integrity Governance Policy and Procedure	80 days	Thu 10/27/11	Wed 2/15/12
345	G.1.3	Conduct Distribution Integrity Audit	60 days	Thu 11/24/11	Wed 2/15/12
346	G.1.4	Review/Improve Distribution Integrity audit checklist	60 days	Thu 1/17/13	Wed 4/10/13
347	G.1.5	Develop 3 year risk management plan	80 days?	Thu 2/16/12	Wed 6/6/12
348	G.1.6	**Review Distribution Integrity Subcommittee Effectiveness Quarterly**	**327 days**	**Fri 1/6/12**	**Mon 4/8/13**
355	G.2	**Review/Improve Survey and Inspection Management**	**341 days**	**Thu 2/16/12**	**Thu 6/6/13**
356	G.2.1	Charter Survey and Inspection Subcommittee	20 days	Thu 2/16/12	Wed 3/14/12
357	G.2.2	Develop Survey and Inspection standard	60 days	Thu 3/15/12	Wed 6/6/12
358	G.2.3	Develop a gap analysis of missing survey & inspection procedures for new facilities	60 days	Thu 6/7/12	Wed 8/29/12
359	G.2.5	Develop survey and inspection implementation plan	60 days	Thu 8/30/12	Wed 11/21/12
360	G.2.6	Implement Survey and Inpsection procedures	100 days	Thu 11/22/12	Wed 4/10/13
361	G.2.7	**Review Survey & Inspection subcommittee Effectiveness Quarterly**	**262 days**	**Wed 6/6/12**	**Thu 6/6/13**
367	G.3	**Review/Improve Material Evaluation & Procurement**	**341 days**	**Thu 2/16/12**	**Thu 6/6/13**
368	G.3.1	Charter Material Evaluation & Procurement Subcommittee	20 days	Thu 2/16/12	Wed 3/14/12
369	G.3.2	Update Material Evaluation & Procurement policy and procedure	60 days	Thu 3/15/12	Wed 6/6/12
370	G.3.3	Develop a material evaluation and procurement implementation plan	60 days	Thu 6/7/12	Wed 8/29/12
371	G.3.4	Implement updated material evaluation & procurement procedures	80 days	Thu 8/30/12	Wed 12/19/12
372	G.3.5	**Review Material Evaluation & Procurement Subcommittee Effectiveness Quarterl**	**262 days**	**Wed 6/6/12**	**Thu 6/6/13**
378	G.4	**Review/Improve Replacement Management**	**220 days**	**Thu 7/5/12**	**Wed 5/8/13**
379	G.4.1	Charter Repairs & Changes Subcommittee	20 days	Thu 7/5/12	Wed 8/1/12
380	G.4.2	Develop Repair & Changes policy and procedure	60 days	Thu 8/2/12	Wed 10/24/12
381	G.4.3	Develop training material for Repairs & Changes procedure	80 days	Thu 10/25/12	Wed 1/16/13
382	G.4.4	Develop implementation plan	60 days	Thu 10/25/12	Wed 1/16/13
383	G.4.5	Implement Repair and Changes	80 days	Thu 1/17/13	Wed 5/8/13
384	G.4.6	**Review Repair & Changes Subcommittee Effectiveness Quarterly**	**130 days**	**Tue 11/6/12**	**Mon 5/6/13**
388	G.5	**Review/Improve Reliability Engineering Management**	**240 days**	**Thu 7/5/12**	**Wed 6/5/13**
389	G.5.1	Charter Reliability Engineering Subcommittee	20 days	Thu 7/5/12	Wed 8/1/12
390	G.5.2	Develop Reliability Engineering policy and Procedure	80 days	Thu 8/2/12	Wed 11/21/12
391	G.5.3	Develop reliability engineering implementation plan	40 days	Thu 11/22/12	Wed 1/16/13
392	G.5.4	Implement Reliability Engineering procedure	100 days	Thu 1/17/13	Wed 6/5/13
393	G.5.5	**Review Reliability Engineering Subcommittee Effectiveness Quarterly**	**130 days**	**Tue 11/6/12**	**Mon 5/6/13**



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SEC INTERROGATORY #3

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: D1/20/1, p. 11

Please provide a copy of the “long term strategic plan” referred to.

RESPONSE

Please see response to SEC Interrogatory #5 (Exhibit I, Issue D20, Schedule 14.5).

Witness: P. Squires

SEC INTERROGATORY #4

INTERROGATORY

D - Operating Costs
Issue 20: Is the proposed O&M budget for Pipeline Integrity & Safety appropriate?

Ref: D1/20/1, p. 14

Please provide a table of FTEs in Pipeline Safety and Integrity, broken down into the three major employee categories, for each of 2007 through 2013.

RESPONSE

Please refer to the response to Board Staff Interrogatory #5 at Exhibit I, Issue D1, Schedule 1.5.

Witnesses: J. Briggs
C. Hanlon
L. Lawler

SEC INTERROGATORY #1

INTERROGATORY

A - General

Please provide the Applicant's most recent Strategic Plan.

RESPONSE

Enbridge respectfully declines to provide a copy of its Strategic Plan. That document is not relevant to this Application, which is intended to effect a cost of service rebasing of Enbridge's rates for 2013. Enbridge's prefiled evidence, as supplemented by the interrogatory responses now being provided, sets out the information required to determine the Company's cost of service for 2013.

In addition, Enbridge notes that its strategic plan contains confidential and commercially sensitive information which is not appropriately disclosed in a public forum.

Witness: P. Squires

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 21: Is the proposed O&M budget for Public and Government Affairs appropriate?

Ref: D1/T21/S1/p. 6

Please provide a detail break-down of the "Outside Services" Budget within the Public and Government Affairs Budget. Please provide the amounts for 2007-2013.

RESPONSE

The table provided on the following page is a summary of “Outside Services” for Public and Government Affairs. It includes bill inserts and customer material production. The 2012 and 2013 budgets contemplate an increase in costs for safety and gas price campaigns to allow for rising print-related market prices such as paper and postage costs and increased quantities to reach a growing customer base. The increase, as described at Exhibit D1, Tab 21, Schedule 1, paragraph 17, is due principally to additional advertising and other community outreach initiatives that relate to core messages around safety, including targeted audiences such as seniors and schools.

Historically, the Public & Government Affairs department has run two safety campaigns each year -- two weeks of safety spots on radio stations each spring to communicate “Call Before You Dig” messages at the start of the digging season and a fall billboard campaign focused on carbon monoxide safety at the start of the heating season.

Additional funds were earmarked to extend the period when safety-related radio spots would be heard and billboards would appear, beyond two weeks. In addition, the increasing use of online media added to the cost forecast.

As well, other avenues to covey messages were identified to increase outreach to increase visibility and retention of safety messages. This includes safety videos and interactive safety-related content on the Company’s website and targeted outreach at safety-related events such as Emergency Preparedness Week.

Witnesses: C. Meyer
M. Sousa

The increase in spending is intended to improve customer satisfaction with Enbridge's safety communications and to increase customer and public education and awareness of natural gas related safety.

	2007	2008	2009	2010	2011	2012	2013
Outside Services	1,736,651	2,085,768	2,227,392	2,227,392	2,474,912	8,786,110	9,199,071

Witnesses: C. Meyer
M. Sousa

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 21: Is the proposed O&M budget for Public and Government Affairs appropriate?

Ref: [D1/21/1, p. 4]

Please provide a more granular breakdown of Outside Services for each year from 2007 through 2013. Please explain why this category increased from $6,187 to $9,199 (48.7%) from 2011 to 2013.

RESPONSE

Outside Services increased from $8,786 (2012 estimate) to $9,199 (2013 budget), a variance of $413, as shown in Exhibit D1, Tab 21, Schedule 1, Table 2. Outside services includes bill inserts and customer material production. The 2012 estimate and 2013 budget both contemplate an increase in costs for safety and gas price campaigns to allow for rising print-related market prices such as paper and postage costs and increased quantities to reach a growing customer base. The $6,187 is the variance between the 2011 Historic Outside Services and 2012 Estimate (Table 3). The increase, as described in Exhibit D1, Tab 21, Schedule 1, paragraph 17, is due to additional advertising and other community outreach initiatives that relate to core messages around safety, including targeted audiences such as seniors and schools.

Historically, the Public & Government Affairs department has run two safety campaigns each year -- two weeks of safety spots on radio stations each spring to communicate “Call Before You Dig” messages at the start of the digging season and a fall billboard campaign focused on carbon monoxide safety at the start of the heating season.

Additional funds were earmarked to extend the period when safety-related radio spots would be heard and billboards would appear, beyond two weeks. In addition, increasing use of online media contributes the higher cost forecast.

As well, other avenues to covey messages were identified to increase outreach, visibility and retention of safety messages. This includes safety videos and interactive safety-related content on our website and targeted outreach at safety-related events such as Emergency Preparedness Week.

Witnesses: C. Meyer
M. Sousa

The increase in spending is intended to improve customer satisfaction with Enbridge's safety communications and to increase customer and public education and awareness of natural gas related safety.

Witnesses: C. Meyer
M. Sousa

SEC INTERROGATORY #2

INTERROGATORY

D - Operating Costs
Issue 21: Is the proposed O&M budget for Public and Government Affairs appropriate?

Ref: D1/21/1, p. 8

Please provide a detailed breakdown of all costs forecast for the Test Year, in any department, relating to "informing and influencing government on public policy issues".

RESPONSE

A breakdown of costs specifically relating to "informing and influencing government on public policy issues" is not available as it is not tracked in that way. For example, in addition to the wages for members of the Public and Government Affairs group, a number of other Enbridge Gas Distribution employees focused attention on reducing third party damages. For example, senior Enbridge Gas Distribution leaders appeared before a legislative committee looking at the issue however the cost of their time is not captured on a project basis. In the same way, municipal meetings on the topic of reducing third party damages often included the local General Manager and this individual's time was also not tracked.

Witnesses: C. Meyer
M. Sousa

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 22: Is the proposed O&M budget for Non-Departmental O&M Expenses appropriate?

Ref: Ex. D1 /Tab 22/ Sch 1 / para 7

With reference to the "scorecards" used to measure and evaluate corporate performance, please describe how the metrics incent the employees of the utility to achieve better performance for the utility's customers and ratepayers specifically.

RESPONSE

The EGD scorecard tracks performance on the following criteria:

- Net Earnings
- Public Safety and Reliability Index
- Employee Safety Index
- Technical Training Composite
- Governance Index
- Customer Satisfaction – Composite Index
- Corporate Brand Index
- Work Environment Composite

Targets are set to ensure EGD's performance is driving shareholder value, customer satisfaction and best employer status. The success of the Company's performance in relation to these criteria will directly benefit the customer and ratepayer through increased customer satisfaction. Employees will have a combination of the above scorecard criteria in their objectives based on the requirements of their position, as well all employees are required to have a safety objective. Employees are evaluated on the completion of their objectives through the performance management process and a minimum threshold of individual performance is required for all employees in order to be eligible to receive an incentive payout. Employees are motivated to attain their objectives, which will ultimately result in better service levels and customer satisfaction.

Witness: S. Trozzi

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 22: Is the proposed O&M budget for Non-Departmental O&M Expenses appropriate?

Ref: D1/T22/S1

Please indicate how many employees are eligible for the STIP. In addition, please indicate the average STP amount forecast for each employee for 2013.

RESPONSE

The total number of employees (head count) at Enbridge Gas Distribution that are eligible for 2013 STIP is 2032. The average STIP amount forecast for each employee is $9,969.00.

Witnesses: R. Lei
S. Trozzi

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 22: Is the proposed O&M budget for Non-Departmental O&M Expenses appropriate?

Ref: Exhibit D1, Tab 22, Schedule 1

a) Please update the table on page 3 to reflect actual 2011 costs and multipliers.

b) Is the Enbridge Inc. Company Multiplier, which is measured by the Corporate Return on Equity, based on EGD's ROE or that of Enbridge Inc.?

c) Please show the calculation of the STIP amounts shown in the table on page 3 (updated to reflect the response to part (a) above) based on the multipliers shown and the base amount to which these multipliers are applied. Please also explain how this base amount is determined.

d) Please show the STIP amounts for 2007 through 2011 if the Enbridge Inc. multiplier had been 1.0 in each year.

RESPONSE

a)

	2011 Actual
Short Term Incentive Program	$25.2M
Enbridge Inc. Multiplier	2.00
Enbridge Multiplier	1.36

b) The Enbridge Inc. Company Multiplier is based on Enbridge Inc.'s Return on Equity.

Witness: S. Trozzi

c) The Short Term Incentive Payout is calculated based on each individual employee's incentive target and performance, as well as the Enbridge Inc. and Enbridge multiplier. All eligible employees will have the same Enbridge Inc. and Enbridge multiplier, in addition, STIP targets vary based on the employee position, individual salaries will vary, and individual performance ratings will vary. The calculation per employee is indicated below:

Annual Salary x Company performance x Business Unit performance, x STIP target x individual performance = Incentive payout

Example to Illustrate:

$100,000 annual salary x 1.0 Company performance x 1.0 Business Unit performance x 20% STIP target x 1.0 (for an individual performance rating of 3.0) = $20,000

d) If the Enbridge Inc. multiplier was 1.0 for each year, the Short Term Incentive Payouts would be as illustrated below:

	2011 $000	2010 $000	2009 $000	2008 $000	2007 $000
Short Term Incentive Payout	$21,402	$17,331	$22,508	$16,616	$17,534
Enbridge Inc. Multiplier	1.00	1.00	1.00	1.00	1.00
Enbridge Multiplier	1.36	1.45	1.68	1.48	1.49

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 22: Is the proposed O&M budget for Non-Departmental O&M Expenses appropriate?

Ref: D1/22/1, p. 3

Please restate the table on this page consistent with the updated evidence.

RESPONSE

The table below has been updated with actuals, estimate and budget. Corrections have also been made to the Enbridge Multiplier in 2010, 2009, 2008 as per the correction filed on July 27, 2012.

	2013 Budget	2012 Estimate	2011 Actual	2010 Actual	2009 Actual	2008 Actual	2007 Actual
Short Term Incentive Program	$20.3M	$19.4M	$25.2M	$19.7M	$25.3M	$19.1M	$20.1M
Enbridge Inc. Multiplier	1.00	1.00	2.00	1.50	2.00	2.00	2.00
Enbridge Multiplier	1.00	1.00	1.36	1.38	1.72	1.78	1.49

Witness: S. Trozzi

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 23: Is the forecast of Provision for Uncollectable Amounts for 2013 appropriate?

Ref: D1/T3/S1/p. 6

Please explain how EGD prepares the forecast for Provision for Uncollectable Accounts.

RESPONSE

A preliminary forecast is developed for Mass Market ("MM") sales which takes into account changes in gas cost; customer additions due to organic growth; and changes in customer counts due to migration between system gas and retailer gas. Based on historical rates of bad debt and potential future developments which may impact customers' ability to pay, the Company assumes that a certain percent of sales will not be collected.

The Company also considers uncollectable accounts related to Large Business Accounts ("LBA") and Sundry Accounts Receivable ("AR"). Given the nature of these portfolios, collectability can vary substantially year to year, impacted by company and industry specific economic conditions, as well as common factors such as commodity price. The Company analyzes trends in historic bad debt amounts for these two categories and bases this forecast on historical experience subject to other factors influencing collectability.

Witnesses: S. Kancharla
R. Lei
S. McGill

SEC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 23: Is the forecast of Provision for Uncollectable Amounts for 2013 appropriate?

Ref: [D1/3/1, p. 10]

Please provide details of the "deficiencies in accounts receivable reporting" in 2011, what steps were taken to correct them, and their impact.

RESPONSE

The details of the deficiencies are described in the Company's response to SEC Interrogatory #3 at Exhibit I, Issue D1, Schedule 14.3.

The adjustments and impacts to the 2011provision for uncollectibles were as follows:

i. Regarding the entry for the true-up between the General Ledger and Accounts Receivable subledger, in order to correct for the issue, the Company booked additional bad debt expense of $2.9 million in 2011 to partially reverse a $4.1 million reduction of bad debt expense that was booked in 2010.

ii. Regarding the understated arrears balances, using information available as at the end of 2011, the Company recognized additional bad debt expense estimated at $4.8 million in order to adequately provide for sales related to 2009 and 2010. This additional amount of bad debt expense would have been booked in 2010 if the same information available at end of 2011 was available at the end of 2010.

Witnesses: S. Kancharla
R. Lei
S. McGill

BOARD STAFF INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 24: Is the allocation of O&M costs between utility and non-utility ("unregulated") operations appropriate?

Ref: Natural Gas Reporting & Record Keeping Requirements (RRR) rule for gas utilities; Ex. A3/Tab 4/Sch 1, 2

Natural Gas RRR 2.1.6 states that:

> A utility shall provide the Board annually, by the last day of the fourth month after the financial year end, audited financial statements for the preceding financial year for the corporate entity regulated by the Board. **Where the financial statements of the corporate entity regulated by the Board contain material businesses not regulated by the Board, the utility shall disclose the information separately according to the segment disclosure provisions** in the Canadian Institute of Chartered Accountants Handbook. [Emphasis added]

It appears that there is no segmented information disclosed for Enbridge's regulated business vs. unregulated business in Enbridge's 2010 and 2011 audited financial statements filed in Ex. A3/Tab 4/Sch 1, 2.

a) Please explain whether the unregulated business is considered by Enbridge as a material business in 2010 and 2011.

b) If the unregulated business is not considered by Enbridge as a material business in 2010 and 2011, please provide Enbridge's threshold for a material business in 2010 and 2011.

c) Please provide Enbridge's external auditor's opinion on management's assessment and decision of not disclosing the segmented information.

d) Does Enbridge plan to prepare and file with the Board audited financial statements for the regulated utility business, excluding the non-regulated business, under the GAAP used in Enbridge's rate applications for the 2012 year and in the future? If not, please explain why the Board should not require to receive annually the

Witnesses: K. Culbert
S. Chhelavda
B. Yuzwa

audited financial statements for the utility it regulates prepared under the GAAP that Enbridge chooses for its rate applications?

RESPONSE

a) The unregulated business in not considered material by Enbridge Gas Distribution ("Enbridge" or the "Company") in 2010 and 2011, as it does not satisfy the criteria set out in the Canadian Institute of Chartered Accountants Handbook section 1701 paragraph 19.

b) The criteria used by Enbridge to determine if the unregulated business is a material business in 2010 and 2011 is section 1701 of Canadian Institute of Chartered Accountants Handbook, which states:

> Enterprises are required to disclose separately information about an operating segment that meets ANY of the following quantitative thresholds:
>
> (a) its reported revenue, including both sales to external customers and intersegment sales or transfers, is 10 percent or more of the combined revenue, internal and external, of all operating segments;
> (b) the absolute amount of its reported profit or loss is 10 percent or more of the greater, in absolute amount, of:
> i. the combined reported profit of all operating segments that did not report loss; or
> ii. the combined reported loss of all operating segments that did report a loss; and
> (c) its assets are 10 percent or more of the combined assets of all operating segments.

c) PricewaterhouseCoopers has expressed an unqualified (clean) opinion on the Company's 2010 and 2011 financial statements. Both the 2010 and 2011 audited financial statements were prepared in accordance with section 1701 of the Canadian Institute of Chartered Accountants Handbook (see b above) which supports management's assessment that the unregulated business is not material.

d) Enbridge plans to file with the Board audited financial statements for its complete operations, which includes unregulated operations under US GAAP for the 2012 rate application and in future years. Utility earnings for the purposes of calculating the 2012 ESM amount will be based on Canadian GAAP, all subsequent years will be based on US GAAP.

Witnesses: K. Culbert
S. Chhelavda
B. Yuzwa

On an annual basis, Enbridge provides a reconciliation of corporate earnings to utility earnings. The Company will continue to provide this reconciliation to the Board.

Witnesses: K. Culbert
S. Chhelavda
B. Yuzwa

CCC INTERROGATORY #1

INTERROGATORY

D - Operating Costs
Issue 24: Is the allocation of O&M costs between utility and non-utility ("unregulated") operations appropriate?

Ref: A1/T9/S1

EGD's purchases from Enbridge Inc. have increased from $39.4 million in 2011 to $45.4 million in 2013. Please provide a schedule setting out all of the reasons for the increase.

RESPONSE

Table 1 below provides the updated 2011 Actual for Enbridge Inc. charges.

Table 1

Particulars ($ Millions)	Budget 2013	Actual 2011	Difference
EGD's purchases from Enbridge Inc. *	$45.4	$41.4	$4.0

* excludes Enbridge Pipeline Inc. Charges

Table 2 found below provides the reasons behind the changes.

Table 2

Particulars ($ Millions)	Budget 2013	Actual 2011	Difference
Stock Based Compensation	$13.0	$13.2	($0.2)
Insurance Premium	8.2	7.2	1.0
Corporate Controller Cost	1.5	1.1	0.4
Legal Knowledge Management and Director's Fees	1.8	1.2	0.6
Public Affairs and Corporate Communications	2.2	2.0	0.2
Employee Benefits	4.5	3.8	0.8
Human Resources Services	4.6	3.4	1.2
Other Enbridge Inc. charges	9.6	9.6	0.0
Total	$45.4	$41.4	$4.0

Witnesses: S. Chhelavda
B. Yuzwa