Lorraine Chiasson
Regulatory Coordinator
Regulatory Affairs

tel 416-495-5499
fax 416-495-6072
EGDRegulatoryProceedings@enbridge.com

Enbridge Gas Distribution
500 Consumers Road
North York, Ontario M2J 1P8
Canada

July 23, 2015

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario
M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge")
Ontario Energy Board File No. EB-2015-0122
2011 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review
Enbridge Interrogatory Responses

In accordance with the Ontario Energy Board's (the "Board") Procedural Order issued for the above noted proceeding, enclosed please find the interrogatory responses of Enbridge.

Included in the package please find a CD which consists of all pre-filed evidence and the interrogatory responses.

This submission was filed through the Board's RESS and will be available on the Company's website at www.enbridgegas.com/ratecase .

Please contact the undersigned if you have any questions.

Yours truly,

[original signed by]

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis LLP
All Interested Parties EB-2012-0276

ENERGY PROBE INTERROGATORY #1

INTERROGATORY

Ref: Exhibit A, Tab 2, Schedule 1, Appendix A

Please confirm that EGDI has used an interest rate of 1.10% for the second and third quarters of 2015.

RESPONSE

Interest calculated on the deferral and variance account balances for the second and third quarters of 2015, with the exception of the CCCISRSDAs, has utilized the Board's prescribed rate for that time period, of 1.10%. Interest calculated on the 2013 and 2014 CCCISRSDAs has however been calculated using a fixed rate of 1.47%, as stipulated in the EB-2011-0226 Customer Care and CIS Cost Settlement Agreement.

Witness: R. Small

APPrO INTERROGATORY #1

INTERROGATORY

Reference: i) Exhibit B Tab 3 Schedule 3 line 3.4

Preamble: The actual revenue collected during 2014 for Rate 125 was $11.0 million compared to the Board approved amount of $9.7 million (increase of approximately 13%). APPrO would like to understand the reasons for this variance.

a) Please provide a variance analysis that fully explains the reasons for the 13% increase in revenues.

b) Please indicate whether or not it is possible that Enbridge may be collecting similarly sourced amounts in the future, and if so does Enbridge intend to incorporate such amounts in its revenue forecasts in any future rate setting applications? If no, please explain why not.

RESPONSE

a) The actual 2014 Rate 125 revenue reported at Exhibit B, Tab 3, Schedule 3. Lline 3.4 is incorrect. A corrected version of this exhibit is attached which states the correct Rate 125 revenues and minor changes to T-Service revenues in other rate classes. Total revenue of $2,887.3 million remains unchanged. The Rate 125 actual revenue for 2014 was $10.1 million. The $10.1 million is comprised of $9.7 million from Rate 125 monthly customer and demand charges and $0.4 million from authorized demand overrun charges and load balancing fees.

b) The revenue forecast for Rate 125 reflects the forecast level of the number of customers and contract demand. The Company does not forecast overrun charges or load balancing fees as it is assumed that customers will match supply and demand on a daily basis and will operate within the parameters of their contract demand levels set out in their contracts. The $0.4 million in authorized demand overrun charges and load balancing fees is higher than other years and relates primarily to one customer incurring high load balancing fees.

Witness: A. Kacicnik

COMPARISON OF GAS SALES AND
TRANSPORTATION REVENUE BY RATE CLASS
2014 HISTORICAL YEAR AND 2014 BOARD APPROVED BUDGET
($ MILLIONS)

Item No.		Col. 1 2014 Actual	Col. 2 2014 Board Approved Budget	Col. 3 2014 Actual Over (Under) 2014 Budget (1-2)	Col. 4 2014* Adjustments	Col. 5 2014 Actual Over (Under) 2014 Budget with Adjustments (3+4)
General Service						
1.1.1	Rate 1 - Sales	1 621.2	1 382.8	238.4	(153.3)	85.1
1.1.2	Rate 1 - T-Service	108.7	88.1	20.6	(6.4)	14.2
1.1	Total Rate 1	1 729.9	1 470.9	259.0	(159.7)	99.3
1.2.1	Rate 6 - Sales	891.1	764.0	127.1	(98.6)	28.5
1.2.2	Rate 6 - T-Service	155.2	111.8	43.4	(12.6)	30.8
1.2	Total Rate 6	1 046.3	875.8	170.5	(111.2)	59.3
1.3.1	Rate 9 - Sales	0.2	0.2	0.0	0.0	0.0
1.3.2	Rate 9 - T-Service	0.0 **	0.0 **	0.0 **	0.0	0.0 **
1.3	Total Rate 9	0.2	0.2	0.0	0.0	0.0
1.	Total General Service Sales & T-Service	2 776.4	2 346.9	429.5	(270.9)	158.6
Contract Sales						
2.1	Rate 100	0.7	0.0	0.7	0.0 **	0.7
2.2	Rate 110	19.2	17.6	1.6	0.0 **	1.6
2.3	Rate 115	0.2	0.2	0.0	0.0	0.0
2.4	Rate 135	1.1	0.2	0.9	0.0	0.9
2.5	Rate 145	4.2	4.1	0.1	0.1	0.2
2.6	Rate 170	7.9	6.2	1.7	0.3	2.0
2.7	Rate 200	31.2	25.2	6.0	(1.6)	4.4
2.	Total Contract Sales	64.5	53.5	11.0	(1.2)	9.8
Contract T-Service						
3.1	Rate 100	0.2	0.0	0.2	0.0 **	0.2
3.2	Rate 110	14.4	13.9	0.5	0.0 **	0.5
3.3	Rate 115	7.2	6.0	1.2	0.0 **	1.2
3.4	Rate 125	10.1	9.7	0.4	0.0 ***	0.4
3.5	Rate 135	2.0	1.5	0.5	0.0	0.5
3.6	Rate 145	4.0	3.3	0.7	0.0 **	0.7
3.7	Rate 170	8.0	(0.6)	8.6	0.1	8.7
3.8	Rate 300	0.1	0.2	(0.1) **	0.0	(0.1)
3.9	Rate 315	0.4	0.0	0.4	0.0	0.4
3.	Total Contract T-Service	46.4	34.0	12.4	0.1	12.5
4.	Total Contract Sales & T-Service	110.9	87.5	23.4	(1.1)	22.3
5.	Total	2 887.3	2 434.4	452.9	(272.0)	180.9

* Note: Weather normalization adjustments have been made to the 2014 Actuals utilizing the 2014 Board Approved Budget degree days in order to place the two years on a comparable basis. Please refer to Exhibit B, Tab 3, Schedule 2, Page 2, for the corresponding volumetric adjustments.

** Less than $50,000

*** There is no distribution volume for Rate 125 customers

Witness: A. Kacicnik

1. Gas sales and transportation of gas revenues for the 2014 Test Year Budget were developed on the basis of EB-2012-0459 rates.

2. The principal reasons for the variances contributing to the increase of $452.9 million in the 2014 Actual under the 2014 Budget are as follows:

3. Gas Sales - Increase of $376.5 Million

   The increase in gas sales revenue was mainly due to higher volume than budgeted and higher actual commodity charges than budgeted

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

4. Transportation of Gas - Increase of $76.4 Million

   The increase in T-service revenue was mainly due to higher volume than budgeted in general service; partially offset by lower volume than budgeted in contract market

   Details on volumes are at Exhibit B, Tab 3, Schedule 2, Pages 1-3.

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 1, Page 1

Please explain the difference in actual and approved costs of (for) property plant and equipment for approximately $112 million.

RESPONSE

The higher cost or redetermined gross plant balance is largely due to the impact of 2012 and 2013 actual plant related activity which was not reflected in the 2014 approved forecast, which utilized the approved 2013 forecast as the starting point. During 2012 and 2013, the actual additions to gross plant were greater than the amounts included within the 2012 and 2013 forecasts. The higher additions were partially offset by higher actual retirements in 2012 and 2013. The result was that the opening 2014 gross plant balance was approximately $80 million higher than the forecast 2014 opening balance.

The higher additions occurred predominantly in 2013 in the mains and services asset categories, and were related to completion of the cast iron program, the unanticipated Don Valley Project, and higher than anticipated costs for customer related activity. The Don Valley Project arose in the spring of 2013 when the Don River experienced unusually high levels of flooding causing erosion of the river bank and exposure of approximately 15 metres of the pipeline. In addition, this pipeline was inline inspected in May 2013 and seven digs were issued, increasing the length of the project to 600 metres. In 2013, the cost of adding new customers increased due to higher direct costs related to customer mix and higher unit costs.

The higher retirements occurred predominantly in 2012, again in the mains and services asset categories, and were primarily related to the cast iron program.

During 2014, the gross plant balance overage continued to grow due to higher gross plant additions, again predominantly in the mains and services asset categories due to overages for the Ottawa Reinforcement Project and customer related activity. The Ottawa Reinforcement Project had difficulties in negotiating and securing working easements with the National Capital Commission, which resulted in restricted access, which negatively impacted construction productivity. Other cost factors included additional rock excavation and hauling and increased material costs from changes required related to the rocky conditions. Similar to 2013, in 2014 the cost of adding new customers increased due to higher direct costs related to customer mix and higher unit costs.

Also contributing to the growth in the gross plant balance in 2014 was lower than forecast retirements (services and software) resulting from assets remaining in use longer than anticipated.

Witnesses: L. Au
T. Knight
R. Small

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1, Pages 1-2

In the calculation of the utility earnings for earning sharing purposes in Exhibit B, Tabs 1 through 5, please explain which tables (figures) are normalized and which are not.

RESPONSE

Within the calculation of actual utility results for earning sharing purposes, the Company calculates normalization adjustments for gas sales and transportation volumes, and gas in storage volumes, resulting in corresponding adjustments to the gas sales and transportation revenues, gas costs, gas cost working cash, and gas in storage values. These adjustments have subsequent impacts on the cost of capital, due to the change in rate base, and income taxes. A comparison of 2014 actual un-normalized versus normalized results is presented in the Attachment included in response to CME Interrogatory #1 found at Exhibit I.B.EGDI.CME.1.

The following exhibits present, contain, or refer to normalized results:

- Exhibit B, Tab 1, Schedule 1,
- Exhibit B, Tab 1, Schedule 2,
- Exhibit B, Tab 1, Schedule 3,
- Exhibit B, Tab 1, Schedule 4,
- Exhibit B, Tab 2, Schedule 1,
- Exhibit B, Tab 2, Schedule 3,
- Exhibit B, Tab 3, Schedule 1,
- Exhibit B, Tab 3, Schedule 2,
- Exhibit B, Tab 3, Schedule 3,
- Exhibit B, Tab 4, Schedule 1,
- Exhibit B, Tab 5, Schedule 1, and
- Exhibit B, Tab 5, Schedule 2.

Witnesses: R. Small

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1, Pages 1-2

(a) What is the purpose of Tab 2, Schedule 2, Pages 1-11? What are the 11 pages designed to demonstrate and what is their role in the determination for earnings sharing purposes? Please explain fully the role of each of the tables.

(b) Please include in the explanation the role of column 7 in each of the tables on pages 2 through 11, and the significance of the "Average of Monthly Overages".

(c) Please explain line 8 in Page 1 of 11 – Affiliate Shared Assets Value.

RESPONSE

a) Exhibit B, Tab 2, Schedule 2 is a property, plant and equipment continuity schedule. Its purpose is to provide details which support the actual property, plant, and equipment balances (gross plant and accumulated depreciation) included as part of rate base, as shown in Exhibit B, Tab 2, Schedule 1, Column 1, Rows 1 through 3. Actual utility rate base is then used in the calculation of the Company's actual required rate of return, the actual achieved rate of return, and resultant sufficiency, as shown in Exhibit B, Tab 1, Schedule 2, and Exhibit B, Tab 5, Schedule 1. Page 1 of Exhibit B, Tab 2, Schedule 2, provides a summary of the average of monthly averages gross plant and accumulated depreciation rate base values broken down by major asset category, which is provided in further detail on pages 2 through 11. The gross plant and accumulated depreciation values for each major asset category are broken down by each asset account on pages 2 through 11, which also shows the annual activity (additions, retirements, depreciation, etc.) which occurred throughout 2014. Finally, the final column on each of pages 2 through 11 also shows the average of monthly averages gross plant and accumulated depreciation value by asset account, which is included within rate base.

b) The final column on each of pages 2 through 11 shows the gross plant and accumulated depreciation Average of Monthly Averages value for each asset account. The values are derived through calculations which take the average of the 12 monthly average gross plant and accumulated depreciation balances by account. The significance of the Average of Monthly Averages is that they are the values which are included within rate base.

c) The Affiliate Shared Assets Value shown on page 1, Line 8, of Exhibit B, Tab 2, Schedule 2, is the non-utility rate base elimination to reflect the use of utility assets by affiliates and third parties.

BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 1, Page 1

When does EGD place capital assets in rate base?

RESPONSE

Capital assets are included within rate base once they are placed into service.

Witness: R. Small

BOMA INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B, Tab 3, Schedule 1, Page 3

Please explain the line 24 "dividend income". Why is it shown as utility income, and then removed?

RESPONSE

The dividend income shown in Exhibit B, Tab 3, Schedule 1, Line 24, Column 1, is shown as part of Enbridge Gas Distribution's Ontario Corporate income, which is the starting point in the determination of utility income. A number of adjustments, such as the elimination of disallowed or unrecoverable amounts, the elimination of non-utility and unregulated amounts, and the elimination of shareholder incentives, are required to convert Enbridge Gas Distribution Ontario Corporate income to utility income. As shown on page 5, of Exhibit B, Tab 3, Schedule 1, the dividend income is eliminated as it relates to the non-utility inter-company financing transaction approved in EBO 179-16. The elimination is consistent with elimination made to the budget which supported the determination of Board Approved 2014 utility income, and the eliminations made within actual results for prior years.

Witness: R. Small

CCC INTERROGATORY #1

INTERROGATORY

Ex. B/T1/S3/p. 2

Please explain why there was an increase in average customer unlocks. How much of the increase in distribution margin was related to the increase in unlocks? Will the higher amount be reflected in rates going forward?

RESPONSE

The increase in 2014 actual average customer unlocks, as compared to the Board approved 2014 forecast, is attributable to lower actual lock meters than forecast. Lock meters are triggered by vacant premises and the non-payment of customer accounts. The 2014 forecast of unlocks was informed by the historical profile of lock meters; however, actual locks were lower than anticipated, contributing to higher actual unlocks in 2014.

The favourable average customer unlock variance resulted in a $5.6 million increase in normalized distribution margin. The higher actual 2014 average customer unlock figure has been incorporated into the forecast of unlocks for 2016, just as available actual information will continue to inform future unlock and volumes forecasts as part of the annual update process within Enbridge's Custom Incentive Regulation plan.

The overage in 2014 actual average unlocks also impacted 2015 rates because as part of the Board-approved Settlement Agreement, in Enbridge's 2015 rate application (EB-2014-0276), volumes and revenues were updated to reflect an increase to the 2015 average customer unlock figure, to reflect half of the 2014 overage in actual average general service customer unlocks.

Witnesses: R. Small
M. Suarez

CCC INTERROGATORY #2

INTERROGATORY

Ex. B/T2/S4/p. 1

Please provide a detailed explanation for the $58.7 million variance related to System Improvements and Upgrades.

RESPONSE

The System Improvement and Upgrades underspend is detailed in Exhibit B, Tab 2, Schedule 4, pages 3 through 5.

A summary of the explanation for the underspend is set out in Table A below.

The primary drivers are higher relocation third party recoveries, lower reinforcements and lower station activity. The bulk of these were due to external factors. The details were provided in the pre-filed evidence as noted in Column 6 of Table A.

The other main driver for the System Improvement and Upgrades underspend is lower overheads. Table 1 of Exhibit B, Tab 2, Schedule 4 presents overall capital spending by category, inclusive of allocated overhead costs. The actual allocation of overhead costs to each category is set out in Table B below. The lower spend in System Improvement activity during 2014, when combined with overspending for Customer Related activity, results in a lower allocation of overheads for System Improvement and a higher allocation of overheads for Customer Related. The overhead costs allocated to System Improvement and Upgrades are $30.1 million less than budget. On an overall basis, overheads are lower than budget by $12.2 million as shown in Table 2 of Exhibit B, Tab 2, Schedule 4 and categorized in Table B below.

Witnesses: L. Au
T. Knight

Table A: System Improvement and Upgrades Variance Drivers

Item		Col 1 Actual	Col 2 Budget	Col 3 Actual Over/(Under)	Col 4 % tage	Col 5 Commentary	Col 6 Paragraph Reference in Ex B/T2/S4
1	Allocated Overheads	54.2	84.3	(30.1)	-36%	Allocation is a function of spend prorated mainly between System improvement and Customer related Capital see Table B below	Par 7
2	Relocation Mains	0.8	15.2	(14.4)	-95%	Higher 3rd Party recoveries	Par 6
3	Reinforcements	3.6	11.4	(7.8)	-68%	Delays due to external factors	Par 10
4	System Integrity and Reliability	125.9	132.3	(6.4)	-5%	Delays due to external factors	Par 11
5	Total System Improvements and Upgrades	**184.5**	**243.2**	**(58.7)**	**-24%**		

Table B: Overheads Allocated

Item		Col 1 Actual	Col 2 Budget	Col 3 Actual Over/(Under)
1	Customer Related	44.7	27.5	17.2
2	System Improvement	54.2	84.3	(30.1)
3	General Plant	4.7	3.4	1.3
4	Storage	2.2	2.8	(0.6)
5	Total Allocated Overheads	**105.8**	**118.0**	**(12.2)**

Witnesses: L. Au
T. Knight

CME INTERROGATORY #1

INTERROGATORY

A. 2014 Actual Earnings

The evidence at Exhibit B**,** Tab 1, Schedule 1 indicates that EGD's actual weather normalized gross overearnings for 2014 were about $25.3M producing a normalized Return on Equity ("ROE") of 10.46%. The Consolidated Financial Statements for EGD at December 31, 2014, at Exhibit D, Tab 6, Schedule 1, page 30, indicate that EGD's actual ROE before weather normalization was 9.4%. In connection with this information, please provide the following:

(a) What were the actual gross over-earnings in ROE before weather normalization? In particular, are these over-earnings in an amount of about $48.3M more than the normalized over-earnings of $25.3M? This $48.3M amount is the difference between:

   (i) The sum of the normalizing adjustments for revenues of $204.6M and $14.4M shown in paragraphs (a) and (b) at Exhibit B, Tab 1, Schedule 4 of page 2; and

   (ii) The normalized costs of $170.6M shown in paragraph (c) in the same Exhibit. If the $48.3M amount is not the correct number to add to $25.3M, then please provide a detailed calculation of the correct amount.

(b) What would the ratepayers' share of gross over-earnings be if the Earnings Sharing Mechanism ("ESM") for EGD was, like the ESM for Union Gas Limited ("Union"), based on actual overearnings rather than weather normalized over-earnings?

(c) Please provide a step-by-step description of the derivation of each of the normalization adjustments in paragraphs (a), (b), (c) in Exhibit B, Tab 1**,** Schedule 4, page 2 of $204.6M in (a), $14.4M in (b) and $170.6M in (c).

(d) Please provide a schedule which will reconcile the actual gross over-earnings and ROE before weather normalization, to be provided in response to question (a) above to the actual corporate equity earnings and ROE of 9.4% shown in the Consolidated Financial Statements for EGD at December 31, 2014. Please include in that reconciliation a description of the major contributors to the reduction of the

Witnesses: J. Barradas
R. Small

actual utility ROE before normalization (to be provided in response to question (a) above) to the actual corporate equity earnings and ROE of 9.4%.

(e) Since the ESM is a mechanism designed to protect ratepayers by remitting to them a portion of over-earnings which exceeds the Board approved ROE, should the ESM in EGD's 5 year Custom Incentive Rates ("IR") regime be converted to one which is applied to actual earnings? Why should EGD receive incentive benefits linked solely to colder than normal weather?

RESPONSE

a) Enbridge Gas Distribution's actual utility gross over-earnings/sufficiency before normalization (including the impact of weather) was $70.6 million, an increase of $45.3 million in comparison to the normalized gross over-earnings. The increase of $45.3 million varies from the $48.3 million referred to in the question, because the amount referred to does not reflect the impact that normalization had on rate base, and its associated impacts (cost of capital and interest tax shield calculations) on the revenue sufficiency calculation. The weather normalization adjustments included a reduction to the gas in storage and gas cost working cash allowance components of rate base. Attachment 1 to this response provides comparisons of the normalized and un-normalized Revenue Sufficiency, Utility Income, and Rate Base calculations.

b) Enbridge's earnings sharing mechanism is clearly stated to be based on weather-normalized over-earnings. The Board specifically acknowledged this in the EB-2012-0459 Decision (at pages 13 and 14). However, if Enbridge's Board-approved earnings sharing mechanism was instead similar to Union's, in that it was based on actual over-earnings rather than weather normalized over-earnings, the ratepayers' 50% share would be $35.3 million. This calculation, however, maintains Enbridge's approved 50/50 sharing of all over-earnings, and is only partially similar to Union's in that it does not reflect their approved methodology where the first 100 basis points of over-earnings is retained by the Company, over-earnings between 101 and 200 basis is shared 50/50 between the ratepayer and the Company, and over-earnings above 200 basis points is shared 90/10 between the ratepayer and the Company.

c) The Company's Board approved weather normalization methodology has been utilized for more than fifteen years. The process isolates the impact of weather on volumes by segregating the actual volumes between heat sensitive and non-heat sensitive load. The heat sensitive volumes and the corresponding revenue and gas costs are adjusted back to the Company's Board Approved Volume forecast.

Witnesses: J. Barradas
R. Small

The 2014 Approved Volume forecast reflects the heating degree days forecast for the Central Region of 3,517, that is 527 degree days below the 2014 actual heating degree days of 4,044. As a result of the colder than forecast weather in 2014, negative normalization adjustments were required to volumes, revenues and gas costs to reflect the forecast weather.

The weather normalization adjustments are determined by adjusting the monthly actual volumes based on the approved heating degree days. These adjustments in 2014 are generated by adding the normalization adjustment of 2014 billed volume to the change in normalization adjustments of December 2014 versus December 2013 unbilled volumes. The total weather normalization adjustment for 2014 is 1,074.1 10^6m^3. Table 1 below illustrates the derivation of this volumetric adjustment.

TABLE 1
2014 Weather Normalization Adjustment

	Col. 1	Col. 2	Col. 3	Col. 4 (Col.1 + Col.2 - Col.3)
	2014 Billed Volume Normalization Adjustment (10^6m^3)	December 2014 Unbilled Normalization Adjustment (10^6m^3)	December 2013 Unbilled Normalization Adjustment (10^6m^3)	Total 2014 Normalization Adjustment (10^6m^3)
Sales	(1046.4)	78.4	(110.3)	(857.7)
T-service	(313.4)	59.5	(37.5)	(216.5)
	(1359.8)	137.9	(147.8)	(1074.1)

- Schedule 2 of Exhibit B, Tab 3, page 2 summarizes the normalization adjustment to the billed volume of 1,359.8 10^6m^3 by rate class as shown in column 1 of the table.

Witnesses: J. Barradas
R. Small

Table 2 below illustrates the derivation of the normalization adjustments for the sales and transportation revenues and the gas cost as shown in paragraph (a), (b), (c) in Exhibit B, Tab 1, Schedule 4, page 2.

TABLE 2
2014 Normalization Adjustments for Gas Sales and Transportation Revenue and Gas Cost

	Col. 1	Col. 2	Col. 3 (Col.1 + Col.2)	Col. 4
	2014 Billed Revenue Normalization Adjustment	December 2014 vs December 2013 Unbilled Revenue Normalization Adjustment	Total 2014 Normalization Adjustment to Revenue	Total 2014 Normalization Adjustment to Gas Cost
	($ millions)	($ millions)	($ millions)	($ millions)
Sales	(253.1)	48.5	(204.6)	(164.9)
T-service	(18.9)	4.6	(14.3)	(5.7)
	(272.0)	53.1	(218.9)	(170.6)

- Schedule 3 of Exhibit B, Tab 3, page 1 summarizes the normalization adjustment of $272.0M by rate class for the gas sales and transportation revenues related to the bill volume as shown in column 1 of the table.
- The normalization adjustment for gas sales revenue of $204.6M as shown in paragraph (a) in Exhibit B, Tab 1, Schedule 4, page 2, is made up of the normalization adjustments for the billed sales revenue of $253.1M, offset by the increase of the change in normalization adjustments of December 2014 versus December 2013 unbilled sales revenues of $48.5M.
- The normalization adjustment for transportation revenue of $14.3M as shown in paragraph (b) in Exhibit B, Tab 1, Schedule 4, page 2, is made up of the normalization adjustments for the billed transportation revenue of $18.9M, offset by the increase of the change in normalization adjustments of December 2014 versus December 2013 unbilled transportation revenues of $4.6M.

The normalization adjustment for gas cost of $170.6M as shown in paragraph (c) in Exhibit B, Tab 1, Schedule 4, page 2, is the sum of the normalization adjustments to gas costs for sales and transportation volumes reflecting PGVA reference prices and transportation tolls.

Witnesses: J. Barradas
R. Small

d) The return on equity ("ROE") of 9.4% shown in the consolidated financial statements is a calculation performed using corporate consolidated income and equity amounts. There are elements within the corporate ROE calculation, examples of which are, the inclusion of St. Lawrence Gas, unregulated, and non-utility amounts, and the use of the average of the actual opening and closing equity balances, which are not relevant or included within the utility return on equity calculation. However, a reconciliation of the corporate consolidated income to the normalized utility income used within the ESM return on equity calculation has been provided at Exhibit B, Tab 1, Schedule 4.

e) The Company does not agree that any change should be made to its ESM. Enbridge Gas Distribution's 2014 earnings sharing amount was calculated using weather normalized actual results, in accordance with the Board's Decision in Enbridge's EB-2012-0459 Customized Incentive Regulation Rate Application, dated July 17, 2014. At page 14 of the Decision, the Board's findings state "The Board will adopt this approach because it ensures that the earnings sharing is based on weather normalized actual results compared to what is embedded in rates." The use of weather normalized actual results is also consistent with EB-2007-0615 Board Approved earning sharing mechanism employed during Enbridge's 2008 through 2012 Incentive Regulation term. Should parties wish to advocate for a different approach to earnings sharing, that should be done in connection with Enbridge's next Incentive Regulation plan, not in the second year of the current Board-approved plan.

Witnesses: J. Barradas
R. Small

REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

		Un-normalized					Normalized				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5 (col 1x col 3)	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10 (col 6 x col 8)
Line No.		Principal	Component	Cost Rate	Return Component	Interest & pref share Expense	Principal	Component	Cost Rate	Return Component	Interest & pref share Expense
		($Millions)	%	%	%		($Millions)	%	%	%	
1.	Long and Medium-Term Debt	2,705.7	56.87	5.41	3.077	146.4	2,705.7	57.55	5.41	3.113	146.4
2.	Short-Term Debt	239.5	5.03	1.38	0.069	3.3	203.1	4.32	1.38	0.060	2.8
3.		2,945.2	61.90		3.146		2,908.8	61.87		3.173	
4.	Preference Shares	100.0	2.10	2.40	0.050	2.4	100.0	2.13	2.40	0.051	2.4
						152.1					151.6
5.	Common Equity	1,712.9	36.00	9.36	3.370		1,692.5	36.00	9.36	3.370	
6.		4,758.1	100.00		6.566		4,701.3	100.00		6.594	
7.	Rate Base	($Millions)			4,758.1		($Millions)			4,701.3	
8.	Utility Income	($Millions)			364.3		($Millions)			328.6	
9.	Indicated Rate of Return				7.656					6.990	
10.	Sufficiency in Rate of Return				1.090					0.396	
11.	Net Sufficiency	($Millions)			51.9		($Millions)			18.6	
12.	Gross Sufficiency	($Millions)			70.6		($Millions)			25.3	
13.	Revenue at Existing Rates	($Millions)			2,861.3		($Millions)			2,642.4	
14.	Allowed Revenue	($Millions)			2,790.7		($Millions)			2,617.1	
15.	Gross Revenue Sufficiency	($Millions)			70.6		($Millions)			25.3	
	Common Equity										
16.	Allowed Rate of Return				9.360					9.360	
17.	Earnings on Common Equity				12.389					10.461	
18.	Sufficiency in Common Equity Return				3.029					1.101	

UTILITY INCOME (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 Un-normalized Utility Income ($Millions)	Col. 2 Normalization Adjustments / Impacts ($Millions)	Col. 3 Normalized Utility Income ($Millions)
1.	Gas sales	2,565.2	(204.6)	2,360.6
2.	Transportation of gas	294.3	(14.3)	280.0
3.	Transmission, compression and storage revenue	1.8	-	1.8
4.	Other operating revenue	43.6	-	43.6
5.	Interest and property rental	-	-	-
6.	Other income	0.3	-	0.3
7.	Total operating revenue	2,905.2	(218.9)	2,686.3
8.	Gas costs	1,815.5	(170.6)	1,644.9
9.	Operation and maintenance (incl. CC/CIS rate smoothing adj.)	408.0	-	408.0
10.	Depreciation and amortization expense	255.9	-	255.9
11.	Fixed financing costs	2.3	-	2.3
12.	Municipal and other taxes	40.5	-	40.5
13.	Interest and financing amortization expense	-	-	-
14.	Other interest expense	-	-	-
15.	Cost of service	2,522.2	(170.6)	2,351.6
16.	Utility income before income taxes	383.0	(48.3)	334.7
17.	Income tax expense	18.7	(12.6)	6.1
18.	Utility income	364.3	(35.7)	328.6

UTILITY RATE BASE (INCLUDING CUSTOMER CARE & CIS)
2014 ACTUAL

Line No.		Col. 1 Un-normalized Rate Base	Col. 2 Normalization Adjustments / Impacts	Col. 3 Normalized Rate Base
		($Millions)	($Millions)	($Millions)
	Property, Plant, and Equipment			
1.	Cost or redetermined value	7,216.6	-	7,216.6
2.	Accumulated depreciation	(2,900.8)	-	(2,900.8)
3.	Net property, plant, and equipment	4,315.8	-	4,315.8
	Allowance for Working Capital			
4	Accounts receivable rebillable projects	1.3	-	1.3
5	Materials and supplies	35.5	-	35.5
6.	Mortgages receivable	0.1	-	0.1
7.	Customer security deposits	(61.4)	-	(61.4)
8.	Prepaid expenses	1.3	-	1.3
9.	Gas in storage	458.4	(55.7)	402.7
10.	Working cash allowance	7.1	(1.1)	6.0
11.	Total Working Capital	442.3	(56.8)	385.5
12.	Utility Rate Base	4,758.1	(56.8)	4,701.3

CME INTERROGATORY #2

INTERROGATORY

B. Under-Spending and Under-Forecasting in 2014 and its Impact in Future Years

The pre-filed evidence at Exhibit B, Tab 2, Schedule 4, at page 1, indicates Capital Under-Spending in 2014 of $99.2M.

At Exhibit B, Tab 3, Schedule 2, page 2, normalized gas sales and transportation volumes are some 137.6 10^6m^3 higher than the Board approved volumes budget of 11,159.1 10^6m^3.

Actual 2014 operating and maintenance ("O&M") expenses at Exhibit B, Tab 4, Schedule 2 were some $14.3M below the Board approved amount of $422.415M.

At Exhibit B, Tab 3, Schedule 5, page 1, actual late payment penalty revenues of $13.1M exceeded Board approved revenues of $10.1M by $3M or about 30%.

In connection with these items, please calculate the gross over-earnings in 2014 related to each of them, namely:

(a) The $99.2M of capital under-spending,

(b) The 137.6 10^6m^3 of under-estimated normalized volumes,

(c) The $3M under-estimate of late payment penalty revenues, and

(d) The $14.3M of O&M expenses under-spent

RESPONSE

The determination of actual earnings and resulting return on equity is affected by the interaction of all variances versus forecast on a combined basis. None of the elements of variance referred to can be viewed as having any discrete impact from an over earnings perspective – the impacts cannot be estimated precisely and/or in isolation of all other variances.

Witnesses: L. Au
T. Knight
R. Small
L. Stickles

As an example of how a focus on variances may be misleading, neither of the WAMS or GTA project planned 2014 spend were anticipated to be in service in 2014 therefore the capital under-spend in these projects has no impact on earnings and resulting return on equity in the year. As another example of how a focus on discrete variances may be misleading, there are items (such as depreciation and debt costs) where Enbridge's expenses were higher than forecast, which contributed to a shortfall in earnings. This is not taken into account when focusing on discrete items that increased earnings.

Accordingly, Enbridge does not agree that the requested calculations are relevant or helpful to the determination of the proper ESM amount. However, to be responsive Enbridge has undertaken a high-level review to estimate the notional stand-alone impact of each of the variances listed:

a) The $99.2 million capital underspend does not in and of itself contribute to over earnings. Earnings and return results are impacted by variances within in service rate base amounts, which are influenced by many factors. For example, the actual 2014 property, plant, and equipment component of rate base amount is higher than Board Approved, which is impacted by 2012 & 2013 fiscal year spend variances which are not being reflected in rates.

b) A simple view of the margin variance associated with the normalized volume variance suggests a gross over earnings impact of approximately $6.8 million. This does not reflect that much of the volume variance was attributable to higher actual average use, the impact of which was captured in the Average Use True-Up Variance Account. In addition, to the extent that a portion of the variance was attributable to a favourable customer variance, this impact does not reflect any associated offsetting cost variances.

c) A $3 million under estimation of late payment penalty revenue would equate to a gross over earnings impact of approximately $3 million. This does not reflect the associated increase in bad debt expense.

d) A $14.3 million O&M underspend would equate to a gross over earnings impact of approximately $14.3 million.

Witnesses: L. Au
T. Knight
R. Small
L. Stickles

CME INTERROGATORY #3

INTERROGATORY

B. Under-Spending and Under-Forecasting in 2014 and its Impact in Future Years

Will the consequences of under-spending and under-forecasting in 2014 likely continue in the years 2015 to 2018 inclusive? If the answer to this question is no, then please provide explain why the 2015 budgets, which will not be adjusted for the 2014 capital under-spending, the 2014 under-estimate of normalized earnings, the 2014 under-estimate of late payment penalties and the 2014 under-estimate of O&M expenses will not tend to be too high by similar amounts in the years 2015 to 2018 inclusive.

RESPONSE

The 2014 spending and forecast variances will not necessarily be repeated or be of similar consequence in any of the years 2015 to 2018. However, the Company anticipates there could be variances in spend and forecast elements relative to Board Approved amounts in any of these years. The review of actual results for each of those years will occur in ESM proceedings for each specific year.

Witnesses: L. Au
T. Knight
R. Small
L. Stickles

ENERGY PROBE INTERROGATORY #2

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1

Did EGDI make any changes to its accounting practices that affect 2014 results? If yes, please explain these changes and indicate why they are not considered material.

RESPONSE

Enbridge has not made any material changes in accounting practices in 2014. During the course of the year, updates or modifications to accounting policies and practices were performed. These changes were considered and implemented in a manner that took into consideration Enbridge-wide accounting policies, USGAAP and the Ontario Energy Board's regulatory rules, and did not result in any material changes to the financial results.

As stated in Exhibit B, Tab 1, Schedule 1, on page 2, for the purposes of the ESM, Enbridge shall calculate its earnings using the regulatory rules prescribed by the Board, from time to time, and shall not make any material changes in accounting practices that have the effect of reducing utility earnings.

Witnesses: L. Stickles
A. Urquhart

ENERGY PROBE INTERROGATORY #3

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 1

The evidence indicates that the earnings sharing amount has increased from $12.0 million in the year end audited statements to $12.65 million, of which $0.6 million is due to the treatment of the April 2014 debt issuance of $300 million. What is the remainder the change ($0.05 million) related to?

RESPONSE

The residual $0.05 million increase in the earnings sharing amount was attributable to the net impact of the following adjustments made after the year-end timelines: a small increase to the shared asset elimination was made to reflect the actual calculation as opposed to the estimate used at year-end, the O&M elimination of the 2013 DSMVA correction recorded in 2014 was added, as it was inadvertently missed at year-end, and rounding impacts resulting from all the adjustments, inclusive of the debt reclassification.

Witness: R. Small

ENERGY PROBE INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 2

Please explain why the amount on line 26 is not 18.62, which is the product of the 0.396% (line 25) and $4,701.3 (line 22) and equivalent to the figure shown on line 42.

RESPONSE

The small variance in the amounts shown on lines 26 and 42 of Exhibit B, Tab 1, Schedule 2, is a rounding variance caused by performing calculations in millions of dollars, and utilizing percentages which have been abbreviated for presentation purposes. In the calculation referenced, the 0.396% shown on line 25, is actually 0.39556% within the calculation, but has been presented to three decimal places.

Witness: R. Small

ENERGY PROBE INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 4

a) Are all of the adjustments between audited consolidated income and utility income consistent with adjustments made in EGDI's previous earnings sharing calculations in 2008 through 2012?

b) If there are any differences please fully explain the difference and the reason for the difference.

RESPONSE

a) The adjustments made to the 2014 audited consolidated income, in the determination of utility income, are consistent with adjustments made in the determination and presentation of actual utility results in previous earnings sharing calculations and other rate proceedings.

Witness: R. Small

ENERGY PROBE INTERROGATORY #6

INTERROGATORY

Ref: Exhibit B, Tab 1, Schedule 3 &
Exhibit B, Tab 2, Schedule 1

In the second reference, it is shown that net property, plant and equipment was $152.8 million higher than forecast in 2014, partly due to lower accumulated depreciation and higher cost or redetermined value. At page 2 of the first reference it is stated that the higher balances were primarily due to higher 2012 and 2013 actual results which were not reflected in the 2014 forecast.

If the higher balances were largely due to higher 2012 and 2013 actual results, please explain why the accumulated depreciation is lower than forecast.

RESPONSE

Similar to the higher cost or re-determined gross plant balance, the lower accumulated depreciation balance is largely due to the impact of 2012 and 2013 actual plant related activity which was not reflected in the 2014 approved forecast, which utilized the approved 2013 forecast as the starting point. During 2012 and 2013, the amount ($) of retirements and cost of retirements, which each debit or lower accumulated depreciation, were each greater than the amounts included within the 2012 and 2013 forecasts. The result was that the opening 2014 accumulated depreciation balance was approximately $50 million lower than the forecast 2014 opening balance. The higher retirements occurred predominantly in 2012 in the mains and services asset categories, and were primarily related to the cast iron program. The higher cost of retirements occurred in 2012, but more predominantly in 2013, again in the mains and services asset categories, and again were primarily related to the cast iron program, but also related to unbudgeted regulator refit abandonments and abandonments related to the unbudgeted Don Valley Replacement. The Don Valley Project arose in the spring of 2013 when the Don River experienced unusually high levels of flooding causing erosion of the river bank and exposure of approximately 15 metres of the pipeline. In addition, this pipeline was inline inspected in May 2013 and seven digs were issued, increasing the length of the project to 600 metres.

Witnesses: L. Au
T. Knight
R. Small

During 2014, the lower opening accumulated depreciation balance was partially offset by the impact of higher than forecast depreciation due to higher gross plant balances and lower than forecast retirements (services and software) resulting from assets remaining in use longer than anticipated, but partially offset by higher cost of retirements due primarily to unbudgeted abandonments for the cast iron program, the regulator refit program and regulated storage wells.

Witnesses: L. Au
T. Knight
R. Small

ENERGY PROBE INTERROGATORY #7

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 3

What were the main factors contributing to the 33% reduction in the 2014 working cash allowance as compared to forecast?

RESPONSE

The primary contributor to the $3.1 million reduction in the working cash allowance is a $2.3 million increase in the O&M working cash credit, resulting from a higher actual O&M value being applied to the negative net O&M lag-day. The higher actual O&M value is due to the inclusion of Customer Care and CIS costs within actual results, but which are removed from the Board Approved working cash calculation. Customer Care and CIS costs are removed from the Approved calculation as the allowed revenues for Customer Care and CIS costs are determined in accordance with the Board Approved EB-2011-0226 methodology. Also contributing to the lower actual working cash allowance is a lower gas cost working cash allowance requirement, resulting from a lower than forecast net gas cost lag-day, partially offset by higher actual normalized gas cost value.

Witness: R. Small

ENERGY PROBE INTERROGATORY #8

INTERROGATORY

Ref: Exhibit B, Tab 4, Schedule 2

a) Please provide an estimate of the total reduction in customer care/CIS service charges (line 18) due to each of the items noted in the explanation.

b) What percentage of customers are on e-billing?

c) Please explain the significant reduction in corporate allocations (line 20) as compared to budget.

RESPONSE

a) The items which contribute to the reduction are: billing and postage $3.4 million, system (back-office) $2.1 million, software licensing $1.1million, CIS IT support $3.5 million.

b) As of December 31, 2014, there were approximately 24% of customers on e-bill.

c) The reduction in corporate allocations of $4.7 million is primarily driven by a higher credit for Enterprise Financial Systems (enterprise costs budgeted at Enbridge Gas Distribution have increased as a result of the Finance Renewal Project, therefore the credit has increased to adjust the budget to Enbridge Gas Distribution's share of its usage), lower insurance premiums from the restructuring of Enbridge Inc's insurance policy, lower stock based compensation costs as a result of a reduction in the number of participants and stock prices, and lower pension costs.

Witnesses: A. Patel
L. Stickles

FRPO INTERROGATORY #1

INTERROGATORY

Ref: Exhibit B, Tab 2, Schedule 1, Page 1

Please provide a table showing the monthly levels in storage and the cost of gas for each month for both the actual and Board approved storage levels to support the reported difference.

RESPONSE

The gas in storage volumetric balances for Utility Rate Base purposes represents the volumetric balance that the utility has in storage and is not representative of the physical balance in storage for planning purposes. These balances include the amount of gas purchased by the Utility to meet seasonal demand and do not include the banked gas account balances of Direct Purchase customers.

A monthly breakdown of the $279.9 million Board Approved gas in storage balance as shown in Column 2 of Exhibit B, Tab 2, Schedule 1, page 1 was based upon the Utility Rate Base volumes as described above and valued at the October 1, 2013 QRAM Reference Price. Column 1 of the attached schedule provides the monthly breakdown of the $279.9 million and Column 2 provides the applicable monthly Utility Rate Base volumes. Column 3 of the attached schedule adjusts the Board Approved forecast to take into consideration the impact of the various QRAM changes throughout 2014.

The 2014 Actual Gas in Storage balance shown in Column 1 of Exhibit B, Tab 2, Schedule 1, page 1 is the normalized average of average gas in storage balances for Utility Rate Base purposes. A monthly breakdown of the $402.7 million was provided at Exhibit B, Tab 2, Schedule 3, page 1, Column 6. For the purposes of this response those monthly values are shown in Column 4 of the attached schedule and the normalized monthly volumetric balances for Utility Rate Base purposes are provided in Column 5.

There are three primary reasons for the difference between the adjusted Board approved balance and the normalized monthly balances. First, as mentioned above, the Utility Rate Base volume does not include the impact of Direct Purchase banked gas account balances and to the extent these balances vary from those assumed in the forecast there will be a difference. Second, the Company recognized early in 2014, a need to move forward its planned injections and as a consequence acquired additional

Witnesses: D. Small
R. Small

volumes earlier than forecast. Consequently, April through to June balances were higher. Thirdly, for the purposes of its 2015 gas supply plan, in order, to have higher storage balances at the end of March 2015 the Company acquired additional supplies in November and December of 2014.

Witnesses: D. Small
R. Small

	Column 1	Column 2	Column 3	Column 4	Column 5
	2014 Board Approved Month-end Storage Balance	10*3 m*3	Adjusted $ value for QRAM changes	Actual Normailzed Gas in Storage Balance as per Exhibit B, Tab 2, Schedule 3, page 1	10*3 m*3
January 1	399.7	1,835,046.1	414.8	413.8	1,691,186.4
January 31	254.7	1,158,185.8	264.3	272.7	1,171,643.7
February 28	134.2	590,113.6	139.1	186.2	738,898.6
March 31	47.8	156,153.3	49.1	130.7	536,411.3
April 30	60.1	187,769.3	70.8	177.2	646,121.2
May 31	123.5	502,853.4	152.1	276.1	1,054,194.3
"June 30	201.2	896,462.8	252.2	391.1	1,499,099.2
July 31	293.1	1,369,783.9	370.9	496.7	1,865,957.4
August 31	385.4	1,846,015.9	490.3	574.2	2,160,769.2
September 30	469.1	2,274,188.5	598.4	641.9	2,432,852.6
October 31	508.6	2,458,385.2	578.5	599.2	2,507,368.2
November 30	483.8	2,339,180.4	550.3	603.4	2,499,747.1
December 31	396.0	1,921,318.7	450.6	553.0	2,389,339.3
Average of Averages	279.9	1,304,772.9	329.0	402.7	1,596,110.5

Reference Price

1-Oct-13	173.817
1-Jan-14	182.043
1-Apr-14	230.667
1-Oct-14	202.237

FRPO INTERROGATORY #2

INTERROGATORY

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

Preamble: "The delay in material shipments had a direct impact resulting in lower labour and overhead costs. As well, land right costs were lower than budgeted. 2015 is the key construction and spend year when virtually all work will be completed."

Please provide updated cost forecasts and the Board approved figures for the components of Material, Labour, Land and Overhead.

RESPONSE

Please see Exhibit D, Tab 1, Schedule 2 which provides a status update of the GTA project.

The total project is forecasted to be $756 million which is approximately $70 million more than the Board Approved budget. The increase is primarily due to higher construction contracts which have escalated due to market conditions. The table below provides a further breakdown.

GTA Reinforcement Project

	Col 1	Col 2	Col 3		Col 4	Col 5	Col 6
	Exh B1/T2/S4 p3				Exh D1/T1/S2		
	2014 Actual	2014 Board Approved Budget	Actual Over / (Under)		Total Forecast	Total Board Approved Budget	Forecast Over / (Under)
Land/Land Rights	60.1	101.8	(41.7)		53.5	101.8	(48.3)
Mains	104.0	95.7	8.3		631.2	504.6	126.6
Stations	8.3	28.8	(20.5)		71.1	80.1	(9.0)
	172.4	226.3	(53.9)		755.8	686.5	69.3

Witnesses: L. Au
S. Dodd
T. Knight

FRPO INTERROGATORY #3

INTERROGATORY

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

Please provide an update on Lost Gas investigations associated with the Storage observation wells.

RESPONSE

Six observation wells were drilled between December 2011 and April 2014. The final observation well drilled was successfully transmitting pressure by May 2014. The six wells currently vary in pressure from 0 to 4760 kPag. Of the six wells, two wells show no potential communication with the nearby storage reefs, three wells show varying degrees of possible communication with the nearby storage reefs and one well shows definite communication but the pressure is lower than expected. Three additional observation wells are likely to be drilled over the next three years to 2018. The Company's reservoir consultant (Sproule) recommends waiting for at least two more years, to allow the storage reefs to better reach pressure stabilization with the adjacent A-1 carbonate reservoirs, before recalculating the LUF (lost and unaccounted for gas). Also, because of the wide range of results obtained so far from the existing observation wells, more observation time is required to accurately assess those respective pressure trends. Enbridge is targeting an LUF-recalculation in early 2017.

Witnesses: L. Au
T. Knight

FRPO INTERROGATORY #4

INTERROGATORY

Ref: Exhibit B, Tab 3, Schedule 1, Page 5

Please provide additional detail and breakdown on the components of this oil and gas adjustment.

RESPONSE

Enbridge produces oil from two of its gas storage pools; the Corunna and Seckerton pools. Oil has been produced from these two pools since 1954, originally by Imperial Oil Limited and subsequently by Enbridge after it purchased the oil reserves from Imperial in the early 1990s. Since the commencement of storage operations, the oil is produced seasonally as the gas pressure in the storage portion of the reservoirs allows. These oil production assets and production operations are held outside of the Company's regulated activities and so the revenues and costs related to oil production operations are eliminated from utility activities and earnings.

The adjustment referred to in Exhibit B, Tab 3, Schedule 1, page 5, relates to the elimination of Board Ordered non-utility oil and gas and unregulated storage activities. Further disaggregation of the amount is not pertinent to the determination of utility results or the earnings sharing amount.

Witness: R. Small

FRPO INTERROGATORY #5

INTERROGATORY

Ref: Exhibit B, Tab 3, Schedule 1, Page 5

Please confirm that these adjustments do not pertain to compensation for Natural Gas liquids related to shipments of gas between AECO and Empress.

RESPONSE

The Company believes the compensation referred to is the revenue received by Enbridge as a result of the processing of natural gas, at a third party extraction plant in Alberta, to produce pipeline quality gas by removing natural gas liquids, which is commonly referred to as “Extraction Revenue”. In accordance with the EB-2013-0046 Decision and Order, extraction revenues received are credited against the Company’s gas acquisition costs and flow back to customers through the PGVA. Therefore, the Company confirms that the adjustments do not pertain to the referenced compensation.

Witness: R. Small

FRPO INTERROGATORY #6

INTERROGATORY

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

Please provide the three factors and the performance relative to target for the Short Term Incentive Program.

RESPONSE

Enbridge Gas Distribution's ("Enbridge's") Short Term Incentive Program ("STIP") is based on the following three factors: 1) Enbridge companywide performance; 2) Enbridge corporate performance; and 3) Individual employee performance.

The table below outlines the STIP targets and the actual results for these three factors for 2014:

METRIC	**TARGET**	**ACTUAL 2014**
Company Wide Performance	1.00	0.70
Business Unit Performance	1.00	1.36
Individual Performance	1.00	1.20

Witnesses: A. Patel
L. Stickles

SEC INTERROGATORY #1

INTERROGATORY

Ref: [B/4/2]

Please file on the record in this proceeding all materials provided by the Applicant to stakeholders at the RCAM Consultative meeting on July 15, 2015.

RESPONSE

The materials presented at the 2014 RCAM Consultative meeting on July 15, 2015 that reviewed the 2013 and 2014 RCAM results are attached.

As can be seen in the attached materials, the Company had expected that its RCAM report and supporting materials would be treated on a without prejudice basis, and not for public distribution. This had been the agreed-upon approach for prior RCAM Consultative meetings and materials. At this time, in order not to delay the process of this ESM application, the Company has decided to produce the 2014 RCAM Consultative meeting materials as requested. However, the Company reserves the right to take the position that materials and discussions from future RCAM Consultative meetings should be treated as without prejudice.

Witnesses: A. Patel
L. Stickles

Corporate Cost Allocation
RCAM Consultative Meeting

July 15, 2015

ENBRIDGE

Information Sharing

The information contained in this report has been prepared in accordance with the terms and conditions of the RCAM Supplementary Settlement Agreement dated September 27, 2007 (RCAM 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 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

RCAM – Overview

1. RCAM has been applied using the Board approved methodology throughout the first generation incentive rate regulation, starting in 2008.

2. RCAM amounts in the five year customized incentive regulation, are based on the same methodology using the 2013 budget and the results of the 2013 MNP Report.

3. RCAM re-calculated each year-end using Enbridge Inc.'s actual budget with any difference factored into the Earnings Sharing Mechanism.

2013 RCAM – Final Update

Continued application of the RCAM methodology, as approved by the OEB in EB-2006-0034, has resulted in:

- 2013 EGD RCAM allocation of $35.2M, a $3.6M or 11.5% increase from 2012
- This reflects a $0.4M reduction from the latest forecast of $35.6M filed on June 28, 2013 under EB-2012-0459 (variance explanations included).

ENBRIDGE

2013 RCAM - Assumptions

- There were no changes made in 2013 to the Board approved RCAM methodology
- There have been no new major developments since our last update on June 28, 2013
- Q3-Q4 2011 and Q1-2 2012 consolidated actual time study results were used to develop the time estimates and the corresponding amounts
- Time estimates were tracked using the same business segments as in the past:
  - EGD
  - Other Gas Distribution Utilities
  - Liquid Pipelines and Major Projects
  - Gas Pipelines
  - Sponsored Investments
  - International
  - Corporate
- Salary weighted time estimates were used to allocate departmental costs
- The approved 2013 EI budget was used to calculate the 2013 RCAM

ENBRIDGE

2014 Highlights

Continued application of the RCAM methodology, as approved by the OEB in EB-2006-0034, has resulted in

- 2014 EGD RCAM allocation amount of $33.6M (as filed under EB-2015-0122 for the 2014 ESM filing), a $1.6M or 4.6% reduction from 2013
  - Direct EFS Credit: $(2.9M)
  - Stock Based Compensation: $(1.4M)
  - Insurance Premiums: $(0.8M)
  - Enterprise System Depreciation: $3.4M

2014 RCAM - Assumptions

- There were no changes made in 2014 to the Board approved RCAM methodology
- Q4 2012 and Q1-3 2013 consolidated actual time study results were used to develop the time estimates and the corresponding amounts
- Time estimates were tracked using the same business segments as in the past:
  - EGD
  - Other Gas Distribution Utilities
  - Liquid Pipelines and Major Projects
  - Gas Pipelines
  - Sponsored Investments
  - International
  - Corporate
- Salary weighted time estimates were used to allocate departmental costs
- The approved 2014 EI budget was used to calculate the 2014 RCAM

2014 YOY Variance Explanations

Direct EFS Credit $(2.9M)

- Due to Finance Renewal Project (FRP) – a major multi-year IT project that continues to invest assets in the next few years
- Enterprise costs budgeted at EGD have increased due to the increase in work related to FRP. As a result EGD has a corresponding higher EFS credit to reflect its fair share of usage of the Enterprise Financial Systems (EFS).

Stock Based Compensation $(1.4M)

- Reduction is a function of number of participants (2014 - 626,506 vs. 2013 - 673,196) and stock prices (2014 - $42.24 vs. 2013 - $44.51)

Insurance Premium $(0.8M)

- The recent restructuring of the Company's insurance policy continues to deliver cost savings in 2014

Enterprise System Depreciation $3.4M

- EFS assets are owned and depreciated by Enbridge Inc.
- Increased investment in EFS assets to implement the FRP roadmap
- As IT infrastructure systems are being centralized at Enbridge Inc., new assets are being acquired at Corporate EI

2007- 2014 Trend

RCAM Trend 2007 - 2014

	2008	2009	2010	2011	2012	2013	2014
Approved by EGD under ISA based on EI's RCAM	$19.1M	$21.1M	$24.3M	$26.7M	$31.6M*	$35.2M	$33.6M
Amount included in rates						$32.1M**	$35.3M

*This included a $0.2M downward adjustment pursuant to the MNP recommendation

** 2012 inflated

Allocation Trends

- EGD's cost allocations as a percent of EI's total budget has declined
  - 2012 – 11.5%
  - 2013 – 10.3%
  - 2014 – 9.3%
- Common allocation factor percentages have also generally declined

General Allocator	2012	2013	2014
Enterprise Headcount	31%	31%	26%
Headcount (non-union)	24%	24%	19%
Capital Employed (FCER)	14%	15%	15%
Capital Employed (ACER)	16%	15%	15%
Audit Fees	26%	24%	21%
Insurance Premium	14%	9%	8%

2014 Restructuring of Services

- Information Technology (IT)
  - Centralization of infrastructure services at Corporate EI. No impact in 2014, but full year impact in 2015.
  - Reorganization of primary services
  - Reclassification of some support services into primary services to reflect the current service delivery model

- Human Resources (HR)
  - Centralization of Payroll Services. No impact in 2014, but full year impact in 2015.
  - Reorganization of primary services, HR Information Systems moved to IT

- Other
  - Reorganization of Public & Government Affairs services
  - Reorganization of Records & Information Management, Enterprise Content Management (ECM) moved to IT

2015 Restructuring of Services

- Information Technology (IT)
  - Centralization of infrastructure services at Corporate EI (2015)
  - Seeking ARC exemption

- Human Resources (HR)
  - Centralization of the broader Human Resource Services (2015) at Corporate EI

Regulatory Cost Allocation Methodology (RCAM) REPORT FOR 2014

(July 15, 2015)

Introduction:

As per the terms of the supplementary Settlement Agreement, Enbridge Gas Distribution ("EGD" or the Company) continued to hold a RCAM consultation for each year under the incentive rate regulation regime starting 2008 with the final one held in 2012.

In the Board decision EB-2012-0459, the Board accepted EGD's proposal to reconvene the RCAM consultative starting 2014 or 2015.

2014 RCAM Report:

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.

2014 Information Package:

The 2014 information package consists of this report and the following accompanying documents:

Document Description	Comments
Attachment 1 to the 2014 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 2013 and 2014.
Attachment 1(a) to the 2014 RCAM Report	• A schedule providing details of the 2014 costs for each service, including Enbridge Inc.'s (EI) 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.
Attachment 1(b) to the 2014 RCAM Report	• Four (4) accompanying schedules to Attachment 1(a) providing further details on 2014 costs: (1) Primary Service Costs;(2) General Expenses and Direct Charges; (3) Return on Invested Capital; and (4) EI's Support Services Cost.

Document Description	Comments
Attachment 2 to the 2014 RCAM Report	• 2014 versus 2013 RCAM Allocations Variance Analysis.
Attachment 3 to the 2014 RCAM Report	• Continuity Statement of EI RCAM Budgets and Allocations to EGD for the period 2007-2014.
Attachment 4 to the 2014 RCAM Report	• 2014 Service Schedules for new services in 2014.

Background Information:

- There have been no changes in methodology in the past year or since the last consultative in 2012.
- The 2014 RCAM allocations to EGD have been determined using EI's approved RCAM budget for 2014 as the cost basis. This is consistent with the practice adopted, 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 2014 (2014 RCAM Confirmation Notice), which has been incorporated into and forms part of the Intercorporate Services Agreement between EGD and EI dated January 1, 2011.
- Enbridge Inc.'s approved RCAM departmental budgets increased by $17.1 million or 5% to $359.6 million in 2014 from $342.5 million in 2013.
- The aggregate threshold for 2014 in respect of RCAM cost allocations to EGD is 5.4%[1].
- The individual service threshold for 2014 is 12.4% and greater than $50,000.[2]

Aggregate Threshold:

- The aggregate corporate cost allocation amounts accepted by the Company for 2013 and 2014 were $35.2 million and $33.6 million, respectively.

The overall decrease in 2014 was $1.6 million or 4.6%. Thus, the aggregate threshold of 5.5% for 2014 has not been triggered.

[1] 2014 Stats Canada for Ontario all-items CPI of 2.4% plus 3%
[2] 2014 Stats Canada for Ontario all-items CPI of 2.4% plus 10%

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 2014 of an increase of 12.4% and an amount greater than $50,000 has been strictly triggered for the following three (3) services, and one (1) general & direct expense item:

  <u>(a) Services (3)</u>

  - Human Resource advice – increase of 82.0% and $140.7K;
  - Planning, Management & Execution of Internal Audits – increase of 47.8% and $116.3K;
  - Records and Information Management – increase of 18.6% and $165.6K

  <u>(b) General Expenses & Direct Charges (1)</u>

  - Direct EFS Charge (credit) – increase of 134.9% and $2,871.1K

- 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 2 (2014 variance analysis, yellow highlighted areas).

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 2014 and beyond. In this connection, the Company confirms that in 2014:
  - No service has been discontinued, however there have been several reorganizations of services (refer to Attachment 2 for details of these services)
  - The following six (6) services and one (1) general & direct expense are new in 2014 due to the reorganizations:

(a) Services (6)

- o Enterprise System Program and Project Management - $1,611.7K;
- o Enterprise Infrastructure Program and Project Management - $86.5K;
- o Enterprise System Management and Technical Support - $4,902.3K;
- o IT Planning and Governance - $1,718.0K
- o Brand Strategy & Community Investment Relations - $247.6K;
- o Government Relations & CSR - $268.3K

(b) General Expenses & Direct Charges (1)

- o Depreciation – Enterprise Systems - $3,392.0K

▪ For the above noted individual services, the service schedules are provided in Attachment 4.

Summary Table of RCAM Direct and Common Cost Allocations to EGD for the years 2014 and 2013

	Services / Direct Charges	2014 Allocation (Based on EI's Approved Budget for 2014) EGD Direct Allocation	2014 EGD Common Allocation	2014 Total Allocation To EGD	2013 Allocation (Based on EI's Approved Budget for 2013) EGD Direct Allocation	2013 EGD Common Allocation	2013 Total Allocation To EGD
Primary Services	Audit & Accounting Advice	$ 40,801	$ 93,542	$ 134,343	$ 39,322	$ 119,096	$ 158,418
	Board of Directors Support	$ 393,875	$ 314,115	$ 707,990	$ 577,856	$ 270,411	$ 848,267
	Business & Economic Financial Analysis	$ -	$ -	$ -	$ -	$ -	$ -
	Business Development	$ 303,345	$ -	$ 303,345	$ 751,127	$ -	$ 751,127
	Capital Market Financing & Access	$ 528,347	$ 217,458	$ 745,805	$ 797,763	$ 231,745	$ 1,029,508
	Cash Management & Banking	$ 142,225	$ 107,292	$ 249,517	$ 339,143	$ 658,337	$ 997,480
	Consolidation and Planning System Technical Support (Khalix)	$ -	$ -	$ -	$ -	$ 275,164	$ 275,164
	Corporate Compliance	$ 63,653	$ 137,888	$ 201,541	$ 91,701	$ 198,661	$ 290,362
	Industry Relations & Corporate Social Responsibility (CSR)	$ -	$ -	$ -	$ 71,423	$ 344,496	$ 415,918
	Emerging Energy Technology Research	$ -	$ -	$ -	$ -	$ -	$ -
	Employee Development	$ 747,592	$ 393,305	$ 1,140,897	$ 975,784	$ 342,813	$ 1,318,597
	Enterprise IT Program Management	$ -	$ -	$ -	$ -	$ 661,348	$ 661,348
	Enterprise IT Strategy Planning & Management	$ -	$ -	$ -	$ -	$ 236,125	$ 236,125
	Expense System Management & Technical Support (Oracle iExpense)	$ -	$ -	$ -	$ -	$ 240,347	$ 240,347
	External Audit Coordination	$ 20,060	$ 83,304	$ 103,364	$ 69,288	$ 137,788	$ 207,076
	Financial and Project Accounting System Technical Support (Oracle)	$ -	$ -	$ -	$ -	$ 517,170	$ 517,170
	Gas Supply, Storage, and Transportation Strategy	$ -	$ -	$ -	$ -	$ -	$ -
	Government Relations	$ -	$ -	$ -	$ 48,971	$ -	$ 48,971
	HRIS Management and Technical Support	$ -	$ -	$ -	$ -	$ 3,487,053	$ 3,487,053
	Human Resource Advice	$ 72,550	$ 239,751	$ 312,301	$ 23,508	$ 148,125	$ 171,633
	Insurance Claims Support, Strategy and Management	$ 171,175	$ 28,105	$ 199,281	$ 236,411	$ 89,159	$ 325,570
	Investor Services	$ 567,621	$ 446,544	$ 1,014,165	$ 737,590	$ 361,857	$ 1,099,448
	Legal Advice	$ 464,192	$ 23,353	$ 487,544	$ 389,921	$ 75,461	$ 465,382
	Planning, Management & Execution of Internal Audits	$ 113,248	$ 246,121	$ 359,369	$ 152,124	$ 90,943	$ 243,067
	Rate Regulated Entity Support	$ 209,479	$ -	$ 209,479	$ 225,727	$ -	$ 225,727
	Records and Information Management	$ -	$ 1,054,087	$ 1,054,087	$ -	$ 888,504	$ 888,504
	Risk Assessment and Management	$ 576,327	$ 77,903	$ 654,230	$ 811,306	$ 54,129	$ 865,435
	Strategic Planning	$ 223,115	$ -	$ 223,115	$ 253,073	$ -	$ 253,073
	Supply Chain Management	$ -	$ 53,482	$ 53,482	$ -	$ 46,900	$ 46,900
	Tax Reporting & Planning	$ 69,348	$ 1,036	$ 70,384	$ 121,445	$ 10,234	$ 131,679
	Total Compensation and Benefits	$ 552,301	$ 1,355,824	$ 1,908,125	$ 473,903	$ 1,925,388	$ 2,399,292
	Employee and Labour Relations	$ 415,706	$ 66,066	$ 481,772	$ 467,113	$ 121,429	$ 588,542
	Portal Suite Operations & Technical Support	$ -	$ -	$ -	$ -	$ 301,334	$ 301,334
	Enterprise System Program and Project Management	$ 58,013	$ 1,553,706	$ 1,611,719	$ -	$ -	$ -
	Enterprise Infrastructure Program and Project Management	$ -	$ 86,548	$ 86,548	$ -	$ -	$ -
	Enterprise System Management and Technical Support	$ 55,047	$ 4,847,258	$ 4,902,304	$ -	$ -	$ -
	Enterprise Infrastructure Management and Technical Support	$ -	$ -	$ -	$ -	$ -	$ -
	IT Planning and Governance	$ 80,771	$ 1,637,233	$ 1,718,004	$ -	$ -	$ -
	Brand Strategy & Community Investment Relations	$ 75,752	$ 171,807	$ 247,559	$ -	$ -	$ -
	Government Relations & CSR	$ 14,176	$ 254,143	$ 268,319	$ -	$ -	$ -
	Payroll Services	$ -	$ -	$ -	$ -	$ -	$ -
	Safety and Process Safety	$ -	$ -	$ -	$ -	$ -	$ -
	Total Service Charges	**$ 5,958,718**	**$ 13,489,869**	**$ 19,448,587**	**$ 7,654,499**	**$ 11,834,017**	**$ 19,488,516**
							$ -
General Expenses & Direct Charges	Direct EFS Charge (Credit)	$ (5,000,103)		$ (5,000,103)	$ (2,129,052)		$ (2,129,052)
	Directors Fees & Expenses	$ 1,223,750		$ 1,223,750	$ 1,089,370		$ 1,089,370
	Depreciation - Risk Management System	$ 25,132		$ 25,132	$ 133,581		$ 133,581
	Depreciation - Enterprise Systems	$ 3,392,008		$ 3,392,008	$ -		$ -
	Insurance Premiums	$ 4,830,857		$ 4,830,857	$ 5,652,239		$ 5,652,239
	BU Stock Based Compensation Charge	$ 9,225,003		$ 9,225,003	$ 10,657,647		$ 10,657,647
	Total Direct Charges	**$ 13,696,647**	**$ -**	**$ 13,696,647**	**$ 15,403,785**	**$ -**	**$ 15,403,785**
	Rate of Return	**$ 471,684**		$ 471,684	**$ 353,189**		**$ 353,189**
	Total EGD Allocation	**$ 20,127,048**	**$ 13,489,869**	**$ 33,616,917**	**$ 23,411,473**	**$ 11,834,017**	**$ 35,245,490**

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Exhibit I.B.EGDI.SEC.1
Attachment
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Attachment 1(a) to the 2014 RCAM Report -
2014 RCAM Allocations to EGD and Other Affiliates

	Services / Direct Charges	EGD Allocation: EGD Direct Allocation	EGD Allocation: EGD Common Allocation	EGD Allocation: Direct Charge & General Expense Allocation	EGD Allocation: EGD Rate of Return	EGD Allocation: Total Allocation To EGD	Other Allocation: Direct Allocation	Other Allocation: Common Allocation	Other Allocation: Direct Charges	Other Allocation: Total Allocation to Other	Total Allocations
Primary Services	1. Aerial Pipeline Surveillance	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	2. Audit & Accounting Advice	$ 40,801	$ 93,542			$ 134,343	$ 1,123,407	$ 548,034		$ 1,671,441	$ 1,805,783
	3. Board of Directors Support	$ 393,875	$ 314,115			$ 707,990	$ 5,341,049	$ 1,840,309		$ 7,181,358	$ 7,889,347
	4. Business & Economic Financial Analysis	$ -	$ -			$ -	$ 5,474,004	$ -		$ 5,474,004	$ 5,474,004
	5. Business Development	$ 303,345	$ -			$ 303,345	$ 15,452,244	$ -		$ 15,452,244	$ 15,755,589
	6. Capital Market Financing & Access	$ 528,347	$ 217,458			$ 745,805	$ 5,385,150	$ 1,274,022		$ 6,659,172	$ 7,404,976
	7. Cash Management & Banking	$ 142,225	$ 107,292			$ 249,517	$ 1,884,480	$ 1,421,625		$ 3,306,106	$ 3,555,623
	8. Enterprise System Program and Project Management	$ 58,013	$ 1,553,706			$ 1,611,719	$ 6,780,423	$ 6,096,456		$ 12,876,879	$ 14,488,598
	9. Corporate Compliance	$ 63,653	$ 137,888			$ 201,541	$ 900,366	$ 774,068		$ 1,674,434	$ 1,875,975
	10. Brand Strategy & Community Investment Relations	$ 75,752	$ 171,807			$ 247,559	$ 3,279,519	$ 964,480		$ 4,243,999	$ 4,491,558
	11. Emerging Energy Technology Research	$ -	$ -			$ -	$ 5,962,010	$ -		$ 5,962,010	$ 5,962,010
	12. Employee Development	$ 747,592	$ 393,305			$ 1,140,897	$ 5,684,684	$ 1,624,649		$ 7,309,333	$ 8,450,229
	13. Enterprise Infrastructure Program and Project Management	$ -	$ 86,548			$ 86,548	$ -	$ 251,886		$ 251,886	$ 338,434
	14. Enterprise IT Strategy Planning & Management - inactive	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	15. Enterprise Infrastructure Management and Technical Support	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	16. External Audit Coordination	$ 20,060	$ 83,304			$ 103,364	$ 692,907	$ 318,877		$ 1,011,784	$ 1,115,148
	17. External Communications	$ -	$ -			$ -	$ 5,062,762	$ -		$ 5,062,762	$ 5,062,762
	18. Enterprise System Management and Technical Support	$ 55,047	$ 4,847,258			$ 4,902,304	$ 4,197,045	$ 13,120,280		$ 17,317,325	$ 22,219,629
	19. Gas Accounting	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	20. Gas Contract Administration	$ -	$ -			$ -	$ 2,944,839	$ -		$ 2,944,839	$ 2,944,839
	21. Gas Supply, Storage, and Transportation Strategy	$ -	$ -			$ -	$ -	$ 382,871		$ 382,871	$ 382,871
	22. Government Relations & CSR	$ 14,176	$ 254,143			$ 268,319	$ 2,822,104	$ 1,426,698		$ 4,248,802	$ 4,517,121
	23. IT Planning and Governance	$ 80,771	$ 1,637,233			$ 1,718,004	$ 4,554,827	$ 5,571,643		$ 10,126,470	$ 11,844,473
	24. Human Resource Advice	$ 72,550	$ 239,751			$ 312,301	$ 2,215,162	$ 696,426		$ 2,911,589	$ 3,223,890
	25. Safety and Process Safety	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	26. Insurance Claims Support, Strategy and Management	$ 171,175	$ 28,105			$ 199,281	$ 2,017,890	$ 316,329		$ 2,334,219	$ 2,533,499
	27. Internal Employee Communications	$ -	$ -			$ -	$ 5,939,921	$ -		$ 5,939,921	$ 5,939,921
	28. Investor Services	$ 567,621	$ 446,544			$ 1,014,165	$ 11,826,072	$ 2,616,169		$ 14,442,241	$ 15,456,406
	30. Legal Advice	$ 464,192	$ 23,353			$ 487,544	$ 11,147,264	$ 131,097		$ 11,278,361	$ 11,765,905
	31. Pension Plan Asset Management and Administration	$ -	$ -			$ -	$ 1,052,993	$ -		$ 1,052,993	$ 1,052,993
	32. Planning, Management & Execution of Internal Audits	$ 113,248	$ 246,121			$ 359,369	$ 2,141,460	$ 942,124		$ 3,083,584	$ 3,442,952
	33. Rate Regulated Entity Support	$ 209,479	$ -			$ 209,479	$ 894,387	$ 143,632		$ 1,038,019	$ 1,247,497
	34. Records and Information Management	$ -	$ 1,054,087			$ 1,054,087	$ -	$ 3,337,699		$ 3,337,699	$ 4,391,786
	35. Reservoir Engineering	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	36. Risk Assessment and Management	$ 576,327	$ 77,903			$ 654,230	$ 10,022,178	$ 456,409		$ 10,478,588	$ 11,132,817
	37. Strategic Planning	$ 223,115	$ -			$ 223,115	$ 7,261,363	$ -		$ 7,261,363	$ 7,484,478
	38. Supply Chain Management	$ -	$ 53,482			$ 53,482	$ -	$ 300,234		$ 300,234	$ 353,716
	39. Tax Advice	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	40. Tax Reporting & Planning	$ 69,348	$ 1,036			$ 70,384	$ 6,895,178	$ 102,987		$ 6,998,165	$ 7,068,549
	41. Total Compensation and Benefits	$ 552,301	$ 1,355,824			$ 1,908,125	$ 2,357,514	$ 3,938,386		$ 6,295,899	$ 8,204,024
	42. Employee and Labour Relations	$ 415,706	$ 66,066			$ 481,772	$ 560,240	$ 191,910		$ 752,150	$ 1,233,922
	43. Payroll Management	$ -	$ -			$ -	$ -	$ -		$ -	$ -
	Total Service Charges	**$ 5,958,718**	**$ 13,489,869**	**$ -**	**$ -**	**$ 19,448,587**	**$ 141,873,444**	**$ 48,789,299**	**$ -**	**$ 190,662,742**	**$ 210,111,329**
General Expenses & Direct Charges	Direct EFS Charge			$ (5,000,103)		$ (5,000,103)				$ -	$ (5,000,103)
	Directors Fees & Expenses			$ 1,223,750		$ 1,223,750			$ 7,474,250	$ 7,474,250	$ 8,698,000
	Depreciation - Risk Management System			$ 25,132		$ 25,132			$ 169,690	$ 169,690	$ 194,822
	Depreciation - Enterprise Systems			$ 3,392,008		$ 3,392,008			$ 16,247,634	$ 16,247,634	$ 19,639,642
	Insurance Premiums			$ 4,830,857		$ 4,830,857			$ 54,371,738	$ 54,371,738	$ 59,202,595
	Audit Fees			$ -		$ -			$ -	$ -	$ -
	EGD Stock Based Compensation Charge			$ 9,225,003		$ 9,225,003			$ -	$ -	$ 9,225,003
	Total Direct Charges	**$ -**	**$ -**	**$ 13,696,647**	**$ -**	**$ 13,696,647**	**$ -**	**$ -**	**$ 78,263,312**	**$ 78,263,312**	**$ 91,959,959**
Not Allocated To EGD	Non-EGD Related Charges Not Allocated to Services									$ 44,273,084	$ 44,273,084
	Support Services Loaded to NonEGD Related Co's									$ 6,224,976	$ 6,224,976
	Adjustment to EI Corp. Gen. Acct.									$ 1,516,462	$ 1,516,462
	EFS True Up									$ 5,000,103	$ 5,000,103
	Directors Fee Credit to EGD (Allocated to Other)									$ 52,000	$ 52,000
	Rate of Return				$ 471,684	$ 471,684					$ 471,684
	Total EGD Allocation	**$ 5,958,718**	**$ 13,489,869**	**$ 13,696,647**	**$ 471,684**	**$ 33,616,917**	**$ 141,873,444**	**$ 48,789,299**	**$ 78,263,312**	**$ 325,992,678**	**$ 359,609,596**

Attachment 1(b) to 2014 RCAM Report
SCHEDULE A - PRIMARY SERVICES

		Primary Service Allocation									
Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
2. Audit & Accounting Advice	Corporate Controller (10047)	$ 19,666,660	3.33%	$ 655,555	5.00%	$ 32,778	38.00%	$ 249,111	14.58%	$ 36,320	$ 69,098
	Enterprise Security (10076)	$ 1,170,989	30.00%	$ 351,297	0.00%	$ -	0.00%	$ -	14.58%	$ -	$ -
	Internal Audit (10050)	$ 4,660,327	9.52%	$ 443,841	0.00%	$ -	60.00%	$ 266,304	14.58%	$ 38,827	$ 38,827
	Support Services	$ 40,511,702	0.88%	$ 355,091	2.26%	$ 8,023	35.53%	$ 126,160	14.58%	$ 18,394	$ 26,417
	TOTAL	**$ 66,009,677**		**$ 1,805,783**		**$ 40,801**		**$ 641,575**		**$ 93,542**	**$ 134,343**

		Primary Service Allocation									
Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
3. Board of Directors Support	CEO (10000)	$ 8,663,107	10.58%	$ 916,731	19.00%	$ 174,179	0.00%	$ -	14.58%	$ -	$ 174,179
	CFO (10045)	$ 5,978,513	2.00%	$ 119,570	15.00%	$ 17,936	0.00%	$ -	14.58%	$ -	$ 17,936
	Corporate Secretarial (10070)	$ 5,602,643	59.09%	$ 3,310,653	2.00%	$ 66,213	6.00%	$ 198,639	14.58%	$ 28,962	$ 95,175
	Total Compensation (10091)	$ 5,590,235	4.60%	$ 257,022	0.00%	$ -	100.00%	$ 257,022	14.58%	$ 37,474	$ 37,474
	Executive VP Law (10078)	$ 4,174,550	16.25%	$ 678,364	1.00%	$ 6,784	0.00%	$ -	14.58%	$ -	$ 6,784
	Corporate Human Resources (10092)	$ 5,829,727	1.12%	$ 65,503	0.00%	$ -	56.00%	$ 36,681	14.58%	$ 5,348	$ 5,348
	HR Strategic Development (10097)	$ 3,025,972	30.00%	$ 907,792	0.00%	$ -	100.00%	$ 907,792	14.58%	$ 132,356	$ 132,356
	People and Partners (10094)	$ 4,335,961	21.74%	$ 942,600	10.00%	$ 94,260	60.00%	$ 565,560	14.58%	$ 82,459	$ 176,719
	Support Services	$ 40,511,702	1.71%	$ 691,113	4.99%	$ 34,504	27.31%	$ 188,729	14.58%	$ 27,517	$ 62,020
	TOTAL	**$ 83,712,410**		**$ 7,889,347**		**$ 393,875**		**$ 2,154,424**		**$ 314,115**	**$ 707,990**

		Primary Service Allocation									
Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
5. Business Development	CEO (10000)	$ 8,663,107	10.58%	$ 916,731	15.00%	$ 137,510	0.00%	$ -	15.12%	$ -	$ 137,510
	CFO (10045)	$ 5,978,513	7.00%	$ 418,496	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Corporate Controller (10047)	$ 19,666,660	2.22%	$ 437,037	6.00%	$ 26,222	0.00%	$ -	15.12%	$ -	$ 26,222
	Tax Services (10049)	$ 6,412,807	3.30%	$ 211,411	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Insurance Risk (10051)	$ 1,555,892	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Enterprise Communications & Community Partners (10072)	$ 13,890,269	8.99%	$ 1,248,564	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Corporate Human Resources (10092)	$ 5,829,727	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Labour Relations (10093)	$ 731,892	10.00%	$ 73,189	5.00%	$ 3,659	0.00%	$ -	15.12%	$ -	$ 3,659
	Alternative and Emerging Technology (10106)	$ 6,613,938	17.17%	$ 1,135,727	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Corporate Development and Planning (10107)	$ 5,863,969	18.89%	$ 1,107,639	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Investment Review (10109)	$ 2,686,924	3.30%	$ 88,580	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	HR Enterprise Business Solutions (10089)	$ 2,464,947	1.23%	$ 30,431	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Support Services	$ 40,511,702	17.43%	$ 7,061,363	1.93%	$ 135,954	0.00%	$ -	15.12%	$ -	$ 135,954
	EGD Charge	$ 2,336,316	0.00%	$ -	1.93%	$ -	0.00%	$ -	15.12%	$ -	$ -
	TOTAL	**$ 123,206,662**		**$ 12,729,167**		**$ 303,345**		**$ -**		**$ -**	**$ 303,345**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
6. Capital Market Financing & Access	CEO (10000)	$ 8,663,107	2.12%	$ 183,346	20.00%	$ 36,669	0.00%	$ -	14.58%	$ -	$ 36,669
	Investor Relations (10043)	$ 2,279,024	9.09%	$ 207,184	0.00%	$ -	50.00%	$ 103,592	14.58%	$ 15,104	$ 15,104
	Treasury (10044)	$ 7,283,481	32.58%	$ 2,373,269	7.00%	$ 166,129	28.00%	$ 664,515	14.58%	$ 96,886	$ 263,015
	CFO (10045)	$ 5,978,513	12.00%	$ 717,422	10.00%	$ 71,742	0.00%	$ -	14.58%	$ -	$ 71,742
	Corporate Secretarial (10070)	$ 5,602,643	9.09%	$ 509,331	2.00%	$ 10,187	7.00%	$ 35,653	14.58%	$ 5,198	$ 15,385
	Support Services	$ 40,511,702	8.43%	$ 3,414,424	7.14%	$ 243,620	20.14%	$ 687,719	14.58%	$ 100,269	$ 343,889
	TOTAL	**$ 70,318,470**		**$ 7,404,976**		**$ 528,347**		**$ 1,491,480**		**$ 217,458**	**$ 745,805**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Time	H = G x Time	I = E + H
7. Cash Management & Banking	Treasury (10044)	$ 7,283,481	42.70%	$ 3,109,801	4.00%	$ 124,392	43.00%	$ 1,337,214	7.02%	$ 93,840	$ 218,232
	Support Services	$ 40,511,702	1.10%	$ 445,822	4.00%	$ 17,833	43.00%	$ 191,703	7.02%	$ 13,453	$ 31,286
	TOTAL	**$ 47,795,182**		**$ 3,555,623**		**$ 142,225**		**$ 1,528,918**		**$ 107,292**	**$ 249,517**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	EFTE	H = G x EFTE	I = E + H
41. Total Compensation and Benefits	CEO (10000)	$ 8,663,107	4.76%	$ 412,529	30.00%	$ 123,759	0.00%	$ -	25.61%	$ -	$ 123,759
	Corporate Controller (10047)	$ 19,666,660	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	Total Compensation (10091)	$ 5,590,235	85.06%	$ 4,754,912	6.00%	$ 285,295	68.00%	$ 3,233,340	25.61%	$ 828,044	$ 1,113,339
	Corporate Human Resources (10092)	$ 5,829,727	7.87%	$ 458,518	0.00%	$ -	36.00%	$ 165,066	25.61%	$ 42,273	$ 42,273
	HR Strategic Development (10097)	$ 3,025,972	30.00%	$ 907,792	0.00%	$ -	100.00%	$ 907,792	25.61%	$ 232,481	$ 232,481
	People and Partners (10094)	$ 4,335,961	21.74%	$ 942,600	10.00%	$ 94,260	55.00%	$ 518,430	25.61%	$ 132,768	$ 227,028
	Support Services	$ 40,511,702	1.80%	$ 727,674	6.73%	$ 48,988	64.53%	$ 469,581	25.61%	$ 120,258	$ 169,245
	TOTAL	**$ 87,623,363**		**$ 8,204,024**		**$ 552,301**		**$ 5,294,210**		**$ 1,355,824**	**$ 1,908,125**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
8. Enterprise System Program and Project Management	CIO (10001)	$ 4,163,983	35.16%	$ 1,464,258	0.00%	$ -	68.00%	$ 995,695	20.31%	$ 202,220	$ 202,220
	IT ES EFS (10040)	$ 2,258,208	33.75%	$ 762,145	0.00%	$ -	100.00%	$ 762,145	20.31%	$ 154,787	$ 154,787
	IT ES ECM (10075)	$ 8,641,268	35.96%	$ 3,106,973	0.00%	$ -	84.00%	$ 2,609,857	20.31%	$ 530,048	$ 530,048
	IT ES HRIS Systems (10095)	$ 4,936,927	25.00%	$ 1,234,232	0.00%	$ -	100.00%	$ 1,234,232	20.31%	$ 250,666	$ 250,666
	IT ES Public Web Systems (10025)	$ 1,854,432	0.00%	$ -	0.00%	$ -	0.00%	$ -	20.31%	$ -	$ -
	IT PG Planning and Governance (10012)	$ 3,755,767	0.00%	$ -	0.00%	$ -	0.00%	$ -	20.31%	$ -	$ -
	IT ES CDM Systems (10014)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	20.31%	$ -	$ -
	IT ES Compliance Systems (10015)	$ 2,028,429	0.00%	$ -	0.00%	$ -	0.00%	$ -	20.31%	$ -	$ -
	IT ES MRM Systems (10016)	$ 7,084,244	76.25%	$ 5,401,736	1.00%	$ 54,017	0.00%	$ -	20.31%	$ -	$ 54,017
	IT ES IAM Systems (10017)	$ 2,091,789	72.73%	$ 1,521,301	0.00%	$ -	100.00%	$ 1,521,301	20.31%	$ 308,968	$ 308,968
	Support Services	$ 40,511,702	2.46%	$ 997,953	0.40%	$ 3,996	52.80%	$ 526,932	20.31%	$ 107,017	$ 111,013
	TOTAL	**$ 77,326,749**		**$ 14,488,598**		**$ 58,013**		**$ 7,650,162**		**$ 1,553,706**	**$ 1,611,719**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
9. Corporate Compliance	CEO (10000)	$ 8,663,107	2.12%	$ 183,346	25.00%	$ 45,837	0.00%	$ -	15.12%	$ -	$ 45,837
	CFO (10045)	$ 5,978,513	2.00%	$ 119,570	10.00%	$ 11,957	0.00%	$ -	15.12%	$ -	$ 11,957
	Corporate Controller (10047)	$ 19,666,660	2.22%	$ 437,037	0.00%	$ -	14.00%	$ 61,185	15.12%	$ 9,251	$ 9,251
	Total Compensation (10091)	$ 5,590,235	10.34%	$ 578,300	0.00%	$ -	100.00%	$ 578,300	15.12%	$ 87,439	$ 87,439
	Corporate Human Resources (10092)	$ 5,829,727	3.37%	$ 196,508	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	People and Partners (10094)	$ 4,335,961	4.35%	$ 188,520	0.00%	$ -	100.00%	$ 188,520	15.12%	$ 28,504	$ 28,504
	Support Services	$ 40,511,702	0.43%	$ 172,694	3.39%	$ 5,860	48.61%	$ 83,951	15.12%	$ 12,693	$ 18,553
	TOTAL	**$ 90,575,905**		**$ 1,875,975**		**$ 63,653**		**$ 911,956**		**$ 137,888**	**$ 201,541**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
10. Brand Strategy & Community Investment Relations	Enterprise Communications & Community Partners (10072)	$ 13,890,269	25.84%	$ 3,589,620	2.00%	$ 71,792	30.00%	$ 1,076,886	15.12%	$ 162,825	$ 234,618
	People and Partners (10094)	$ 4,335,961	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Support Services	$ 40,511,702	0.58%	$ 234,801	1.69%	$ 3,960	25.30%	$ 59,401	15.12%	$ 8,981	$ 12,941
	TOTAL	**$ 58,737,931**		**$ 3,824,421**		**$ 75,752**		**$ 1,136,287**		**$ 171,807**	**$ 247,559**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
11. Emerging Energy Technology Research	Alternative and Emerging Technology (10106)	$ 6,613,938	82.83%	$ 5,478,211	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Corporate Development and Planning (10107)	$ 5,863,969	0.00%	$ -	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	Support Services	$ 40,511,702	1.19%	$ 483,799	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	TOTAL	**$ 52,989,608**		**$ 5,962,010**		**$ -**		**$ -**		**$ -**	**$ -**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Non-Union EFTE	H = G x Non-Union EFTE	I = E + H
12. Employee Development	CEO (10000)	$ 8,663,107	6.35%	$ 550,039	45.00%	$ 247,517	0.00%	$ -	19.49%	$ -	$ 247,517
	Organizational Effectiveness (10090)	$ 4,813,890	100.00%	$ 4,813,890	8.00%	$ 385,111	16.00%	$ 770,222	19.49%	$ 150,119	$ 535,230
	Corporate Human Resources (10092)	$ 5,829,727	19.10%	$ 1,113,543	0.00%	$ -	0.00%	$ -	19.49%	$ -	$ -
	People and Partners (10094)	$ 4,335,961	5.43%	$ 235,650	20.00%	$ 47,130	40.00%	$ 94,260	19.49%	$ 18,372	$ 65,502
	HR Strategic Development (10097)	$ 3,025,972	20.00%	$ 605,194	0.00%	$ -	100.00%	$ 605,194	19.49%	$ 117,954	$ 117,954
	HR Enterprise Business Solutions (10089)	$ 2,464,947	14.81%	$ 365,177	0.00%	$ -	100.00%	$ 365,177	19.49%	$ 71,174	$ 71,174
	Support Services	$ 40,511,702	1.89%	$ 766,735	8.85%	$ 67,833	23.88%	$ 183,100	19.49%	$ 35,687	$ 103,520
	TOTAL	**$ 69,645,306**		**$ 8,450,229**		**$ 747,592**		**$ 2,017,954**		**$ 393,305**	**$ 1,140,897**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x ACER	I = E + H
13. Enterprise Infrastructure Program and Project Management	CIO (10001)	$ 4,163,983	7.69%	$ 320,306	0.00%	$ -	100.00%	$ 320,306	25.57%	$ 81,912	$ 81,912
	IT PG Planning and Governance (10012)	$ 3,755,767	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.57%	$ -	$ -
	IT ISS Management (10031)	$ 660,000	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.57%	$ -	$ -
	IT ISS Security Operations (10019)	$ 1,683,895	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.57%	$ -	$ -
	Support Services	$ 40,511,702	0.04%	$ 18,128	0.00%	$ -	100.00%	$ 18,128	25.57%	$ 4,636	$ 4,636
	TOTAL	**$ 50,775,347**		**$ 338,434**		**$ -**		**$ 338,434**		**$ 86,548**	**$ 86,548**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
15. Enterprise Infrastructure Management and Technical Support	CIO (10001)	$ 4,163,983	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	IT ISS Management (10031)	$ 660,000	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	IT ISS Security Operations (10019)	$ 1,683,895	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	Support Services	$ 40,511,702	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	TOTAL	**$ 47,019,580**		**$ -**		**$ -**		**$ -**		**$ -**	**$ -**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Audit Fees	H = G x Audit Fees	I = E + H
16. External Audit Coordination	CFO (10045)	$ 5,978,513	2.00%	$ 119,570	15.00%	$ 17,936	0.00%	$ -	20.71%	$ -	$ 17,936
	Corporate Controller (10047)	$ 19,666,660	3.33%	$ 655,555	0.00%	$ -	21.00%	$ 137,667	20.71%	$ 28,515	$ 28,515
	Internal Audit (10050)	$ 4,660,327	4.76%	$ 221,920	0.00%	$ -	100.00%	$ 221,920	20.71%	$ 45,966	$ 45,966
	Support Services	$ 40,511,702	0.29%	$ 118,102	1.80%	$ 2,124	36.07%	$ 42,594	20.71%	$ 8,822	$ 10,947
	TOTAL	**$ 70,817,202**		**$ 1,115,148**		**$ 20,060**		**$ 402,181**		**$ 83,304**	**$ 103,364**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		Primary Service Allocation									
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
18. Enterprise System Management and Technical Support	CIO (10001)	$ 4,163,983	21.98%	$ 915,161	0.00%	$ -	44.00%	$ 402,671	26.98%	$ 108,632	$ 108,632
	IT ES CDM Systems (10014)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	26.98%	$ -	$ -
	IT ES Compliance Systems (10015)	$ 2,028,429	0.00%	$ -	0.00%	$ -	0.00%	$ -	26.98%	$ -	$ -
	IT ES MRM Systems (10016)	$ 7,084,244	23.75%	$ 1,682,508	3.00%	$ 50,475	0.00%	$ -	26.98%	$ -	$ 50,475
	IT ES IAM Systems (10017)	$ 2,091,789	27.27%	$ 570,488	0.00%	$ -	100.00%	$ 570,488	26.98%	$ 153,905	$ 153,905
	IT ES Public Web Systems (10025)	$ 1,854,432	0.00%	$ 60,004	0.00%	$ -	100.00%	$ 60,004	26.98%	$ 16,188	$ 16,188
	IT ES ECM (10075)	$ 8,641,268	64.04%	$ 7,268,495	0.00%	$ -	85.00%	$ 6,178,221	26.98%	$ 1,666,752	$ 1,666,752
	IT ES HRIS Systems (10095)	$ 4,936,927	75.00%	$ 5,002,295	0.00%	$ -	100.00%	$ 5,002,295	26.98%	$ 1,349,512	$ 1,349,512
	HR Enterprise Business Solutions (10089)	$ 2,464,947	83.95%	$ 2,069,338	0.00%	$ -	100.00%	$ 2,069,338	26.98%	$ 558,263	$ 558,263
	Corporate Human Resources (10092)	$ 5,829,727	22.47%	$ 1,310,051	0.00%	$ -	68.00%	$ 890,835	26.98%	$ 240,328	$ 240,328
	IT ISS Security Operations (10019)	$ 1,878,717	0.00%	$ -	0.00%	$ -	0.00%	$ -	26.98%	$ -	$ -
	IT ES EFS (10040)	$ 2,258,208	66.25%	$ 1,496,062	0.00%	$ -	87.00%	$ 1,301,574	26.98%	$ 351,137	$ 351,137
	Support Services	$ 40,511,702	4.55%	$ 1,845,226	0.25%	$ 4,571	80.86%	$ 1,492,112	26.98%	$ 402,540	$ 407,111
	TOTAL	**$ 83,744,373**		**$ 22,219,629**		**$ 55,047**		**$ 17,967,538**		**$ 4,847,258**	**$ 4,902,304**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Time	H = G x Time	I = E + H
21. Gas Supply, Storage, and Transportation Strategy	CEO (10000)	$ 8,663,107	3.17%	$ 275,019	0.00%	$ -	100.00%	$ 275,019	0.00%	$ -	$ -
	Support Services	$ 40,511,702	0.27%	$ 107,852	0.00%	$ -	100.00%	$ 107,852	0.00%	$ -	$ -
	TOTAL	**$ 49,174,809**		**$ 382,871**		**$ -**		**$ 382,871**		**$ -**	**$ -**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
22. Government Relations & CSR	Public, Government & Aboriginal Affairs (10118)	$ 5,819,367	56.82%	$ 3,306,458	0.40%	$ 13,226	34.60%	$ 1,144,035	15.12%	$ 172,978	$ 186,204
	People and Partners (10094)	$ 4,335,961	9.78%	$ 424,170	0.00%	$ -	100.00%	$ 424,170	15.12%	$ 64,135	$ 64,135
	Support Services	$ 40,511,702	0.75%	$ 302,702	0.31%	$ 950	37.21%	$ 112,637	15.12%	$ 17,031	$ 17,981
	TOTAL	**$ 50,667,029**		**$ 4,033,330**		**$ 14,176**		**$ 1,680,841**		**$ 254,143**	**$ 268,319**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
23. IT Planning and Governance	CIO (10001)	$ 4,163,983	35.16%	$ 1,464,258	0.00%	$ -	100.00%	$ 1,464,258	22.71%	$ 332,553	$ 332,553
	IT PG Planning and Governance (10012)	$ 3,755,767	100.00%	$ 3,755,767	0.00%	$ -	53.00%	$ 1,990,557	22.71%	$ 452,082	$ 452,082
	IT PG Architecture (10032)	$ 2,136,830	100.00%	$ 2,136,830	0.00%	$ -	100.00%	$ 2,136,830	22.71%	$ 485,303	$ 485,303
	IT PG Security (10033)	$ 1,894,975	100.00%	$ 1,894,975	0.00%	$ -	49.00%	$ 928,538	22.71%	$ 210,883	$ 210,883
	Executive VP Law (10078)	$ 4,174,550	35.00%	$ 1,461,093	5.00%	$ 73,055	0.00%	$ -	22.71%	$ -	$ 73,055
	Support Services	$ 40,511,702	2.79%	$ 1,131,551	0.68%	$ 7,716	60.86%	$ 688,693	22.71%	$ 156,412	$ 164,128
	TOTAL	**$ 56,637,807**		**$ 11,844,473**		**$ 80,771**		**$ 7,208,875**		**$ 1,637,233**	**$ 1,718,004**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	EFTE	H = G x EFTE	I = E + H
24. Human Resource Advice	CEO (10000)	$ 8,663,107	1.06%	$ 91,673	20.00%	$ 18,335	0.00%	$ -	25.61%	$ -	$ 18,335
	Enterprise Security (10076)	$ 1,170,989	20.00%	$ 234,198	20.00%	$ 46,840	0.00%	$ -	25.61%	$ -	$ 46,840
	HR Strategic Development (10097)	$ 3,025,972	20.00%	$ 605,194	0.00%	$ -	100.00%	$ 605,194	25.61%	$ 154,988	$ 154,988
	Corporate Human Resources (10092)	$ 5,829,727	33.71%	$ 1,965,077	0.00%	$ -	12.00%	$ 235,809	25.61%	$ 60,390	$ 60,390
	Support Services	$ 40,511,702	0.81%	$ 327,748	2.25%	$ 7,376	29.04%	$ 95,174	25.61%	$ 24,374	$ 31,749
	TOTAL	**$ 59,201,497**		**$ 3,223,890**		**$ 72,550**		**$ 936,177**		**$ 239,751**	**$ 312,301**

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	EFTE	H = G x EFTE	I = E + H
25. Safety and Process Safety	Enterprise Safety & Operational Reliability (10880)	$ 2,307,455	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	Support Services	$ 40,511,702	0.00%	$ -	#DIV/0!	$ -	#DIV/0!	$ -	25.61%	$ -	$ -
	TOTAL	$ 42,819,157		$ -		$ -		$ -		$ -	$ -

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Insurance Premiums	H = G x Insurance Premiums	I = E + H
26. Insurance Claims Support, Strategy and Management	CFO (10045)	$ 5,978,513	4.00%	$ 239,141	0.00%	$ -	100.00%	$ 239,141	8.16%	$ 19,514	$ 19,514
	Enterprise Risk (10046)	$ 12,793,175	3.30%	$ 421,753	6.00%	$ 25,305	0.00%	$ -	8.16%	$ -	$ 25,305
	Insurance Risk (10051)	$ 1,555,892	100.00%	$ 1,555,892	8.00%	$ 124,471	4.00%	$ 62,236	8.16%	$ 5,078	$ 129,550
	Support Services	$ 40,511,702	0.78%	$ 316,714	6.76%	$ 21,399	13.60%	$ 43,058	8.16%	$ 3,513	$ 24,912
	EPI Charge	$ 10,029,242	0.00%	$ -	6.76%	$ -	13.60%	$ -	8.16%	$ -	$ -
	TOTAL	$ 70,868,524		$ 2,533,499		$ 171,175		$ 344,434		$ 28,105	$ 199,281

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
28. Investor Services	CEO (10000)	$ 8,663,107	14.81%	$ 1,283,423	15.00%	$ 192,513	0.00%	$ -	14.58%	$ -	$ 192,513
	Investor Relations (10043)	$ 2,279,024	90.91%	$ 2,071,840	0.00%	$ -	32.00%	$ 662,989	14.58%	$ 96,664	$ 96,664
	Treasury (10044)	$ 7,283,481	3.37%	$ 245,511	3.00%	$ 7,365	48.00%	$ 117,845	14.58%	$ 17,182	$ 24,547
	CFO (10045)	$ 5,978,513	9.00%	$ 538,066	5.00%	$ 26,903	0.00%	$ -	14.58%	$ -	$ 26,903
	Corporate Secretarial (10070)	$ 5,602,643	6.82%	$ 381,998	0.00%	$ -	7.00%	$ 26,740	14.58%	$ 3,899	$ 3,899
	Enterprise Communications & Community Partners (10072)	$ 13,890,269	8.99%	$ 1,248,564	0.00%	$ -	22.00%	$ 274,684	14.58%	$ 40,049	$ 40,049
	People and Partners (10094)	$ 4,335,961	3.26%	$ 141,390	0.00%	$ -	100.00%	$ 141,390	14.58%	$ 20,615	$ 20,615
	Support Services	$ 40,511,702	16.99%	$ 6,881,098	3.67%	$ 252,702	19.82%	$ 1,363,501	14.58%	$ 198,798	$ 451,500
	Corporate Secretarial Legal Fees (10024)	$ 2,400,000	100.00%	$ 2,400,000	3.67%	$ 88,138	19.82%	$ 475,564	14.58%	$ 69,337	$ 157,475
	TOTAL	$ 90,944,699		$ 15,191,889		$ 567,621		$ 3,062,713		$ 446,544	$ 1,014,165

Service	Department	Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	EFTE	H = G x EFTE	I = E + H
Employee and Labour Relations (Combined)	Corporate Human Resources (10092)	$ 5,829,727	7.87%	$ 458,518	14.29%	$ 65,503	0.09%	$ 393	25.61%	$ 101	$ 65,603
	Labour Relations (10093)	$ 731,892	90.00%	$ 658,703	50.00%	$ 329,351	30.00%	$ 197,611	25.61%	$ 50,607	$ 379,959
	People and Partners (10094)	$ 4,335,961	1.09%	$ 47,130	0.00%	$ -	100.00%	$ 47,130	25.61%	$ 12,070	$ 12,070
	Support Services	$ 40,511,702	0.17%	$ 69,571	29.97%	$ 20,852	18.46%	$ 12,842	25.61%	$ 3,289	$ 24,141
	EGD Charge	$ 2,336,316	0.00%	$ -	32.13%	$ -	38.62%	$ -	25.61%	$ -	$ -
	TOTAL	$ 53,745,598		$ 1,233,922		$ 415,706		$ 257,976		$ 66,066	$ 481,772

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
30. Legal Advice	Corporate Secretarial (10070)	$ 5,602,643	25.00%	$ 1,400,661	1.00%	$ 14,007	0.00%	$ -	15.12%	$ -	$ 14,007
	Executive VP Law (10078)	$ 4,174,550	37.50%	$ 1,565,456	5.00%	$ 78,273	0.00%	$ -	15.12%	$ -	$ 78,273
	Enterprise Security (10076)	$ 1,170,989	30.00%	$ 351,297	10.00%	$ 35,130	0.00%	$ -	15.12%	$ -	$ 35,130
	Corporate Law and Compliance (10077 and 10081)	$ 9,390,654	67.47%	$ 6,335,863	4.00%	$ 253,435	2.00%	$ 126,717	15.12%	$ 19,160	$ 272,594
	Support Services	$ 40,511,702	1.83%	$ 742,068	3.95%	$ 29,276	1.31%	$ 9,741	15.12%	$ 1,473	$ 30,749
	Corporate Law Legal Fees (10020)	$ 625,000	100.00%	$ 625,000	3.95%	$ 24,658	1.31%	$ 8,204	15.12%	$ 1,240	$ 25,898
	EGD Charge	$ 2,336,316	0.56%	$ 13,000	0.00%	$ -	0.00%	$ -	15.12%	$ -	$ -
	EPI Charge	$ 10,029,242	7.43%	$ 745,561	3.95%	$ 29,414	1.31%	$ 9,787	15.12%	$ 1,480	$ 30,894
	TOTAL	**$ 73,841,097**		**$ 11,778,905**		**$ 464,192**		**$ 154,449**		**$ 23,353**	**$ 487,544**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Audit Fees	H = G x Audit Fees	I = E + H
32. Planning, Management & Execution of Internal Audits	CFO (10045)	$ 5,978,513	2.00%	$ 119,570	10.00%	$ 11,957	0.00%	$ -	20.71%	$ -	$ 11,957
	Internal Audit (10050)	$ 4,660,327	59.52%	$ 2,774,004	3.00%	$ 83,220	36.00%	$ 998,641	20.71%	$ 206,849	$ 290,069
	Support Services	$ 40,511,702	1.29%	$ 522,705	3.29%	$ 17,193	34.51%	$ 180,398	20.71%	$ 37,366	$ 54,559
	EPI Charge	$ 10,029,242	0.27%	$ 26,673	3.29%	$ 877	34.51%	$ 9,205	20.71%	$ 1,907	$ 2,784
	TOTAL	**$ 61,179,784**		**$ 3,442,952**		**$ 113,248**		**$ 1,188,245**		**$ 246,121**	**$ 359,369**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	N/A	H = G x N/A	I = E + H
33. Rate Regulated Entity Support	Treasury (10044)	$ 7,283,481	2.25%	$ 163,674	5.00%	$ 8,184	73.00%	$ 119,482	0.00%	$ -	$ 8,184
	Corporate Controller (10047)	$ 19,666,660	4.44%	$ 874,074	19.00%	$ 166,074	0.00%	$ -	0.00%	$ -	$ 166,074
	Support Services	$ 40,511,702	0.52%	$ 209,750	16.79%	$ 35,221	11.51%	$ 24,150	0.00%	$ -	$ 35,221
	EGD Charge	$ 2,336,316	4.28%	$ 100,000	0.00%	$ -	0.00%	$ -	0.00%	$ -	$ -
	TOTAL	**$ 69,798,158**		**$ 1,347,497**		**$ 209,479**		**$ 143,632**		**$ -**	**$ 209,479**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
34. Records and Information Management	Corporate Law and Compliance (10077 and 10081)	$ 9,390,654	14.46%	$ 1,357,685	0.00%	$ -	100.00%	$ 1,357,685	24.00%	$ 325,863	$ 325,863
	Records Management (10079)	$ 2,532,496	100.00%	$ 2,532,496	0.00%	$ -	100.00%	$ 2,532,496	24.00%	$ 607,833	$ 607,833
	Support Services	$ 40,511,702	1.24%	$ 501,606	0.00%	$ -	100.00%	$ 501,606	24.00%	$ 120,392	$ 120,392
	TOTAL	**$ 52,434,852**		**$ 4,391,786**		**$ -**		**$ 4,391,786**		**$ 1,054,087**	**$ 1,054,087**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
36. Risk Assessment and Management	CEO (10000)	$ 8,663,107	1.06%	$ 91,673	10.00%	$ 9,167	0.00%	$ -	14.58%	$ -	$ 9,167
	Enterprise Risk (10046)	$ 12,793,175	68.13%	$ 8,716,229	5.00%	$ 435,811	3.00%	$ 261,487	14.58%	$ 38,125	$ 473,936
	CFO (10045)	$ 5,978,513	8.00%	$ 478,281	10.00%	$ 47,828	0.00%	$ -	14.58%	$ -	$ 47,828
	Corporate Controller (10047)	$ 19,666,660	0.00%	$ 0	0.00%	$ -	0.00%	$ -	14.58%	$ -	$ -
	Internal Audit (10050)	$ 4,660,327	11.90%	$ 554,801	3.00%	$ 16,644	38.00%	$ 210,824	14.58%	$ 30,738	$ 47,382
	Enterprise Safety & Operational Reliability (10880)	$ 2,307,455	0.00%	$ -	0.00%	$ -	0.00%	$ -	14.58%	$ -	$ -
	Support Services	$ 40,511,702	3.19%	$ 1,291,833	5.18%	$ 66,876	4.80%	$ 62,001	14.58%	$ 9,040	$ 75,916
	TOTAL	**$ 94,580,939**		**$ 11,132,817**		**$ 576,327**		**$ 534,312**		**$ 77,903**	**$ 654,230**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	FCER	H = G x FCER	I = E + H
37. Strategic Planning	CEO (10000)	$ 8,663,107	21.16%	$ 1,833,462	10.00%	$ 183,346	0.00%	$ -	14.58%	$ -	$ 183,346
	Treasury (10044)	$ 7,283,481	5.62%	$ 409,184	0.00%	$ -	0.00%	$ -	14.58%	$ -	$ -
	Enterprise Risk (10046)	$ 12,793,175	6.59%	$ 843,506	3.00%	$ 25,305	0.00%	$ -	14.58%	$ -	$ 25,305
	Support Services	$ 40,511,702	1.20%	$ 485,189	2.98%	$ 14,464	0.00%	$ -	14.58%	$ -	$ 14,464
	TOTAL	**$ 69,251,464**		**$ 3,571,341**		**$ 223,115**		**$ -**		**$ -**	**$ 223,115**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	ACER	H = G x ACER	I = E + H
38. Supply Chain Management	CFO (10045)	$ 5,978,513	2.00%	$ 119,570	0.00%	$ -	100.00%	$ 119,570	15.12%	$ 18,079	$ 18,079
	Corporate Administration (10071)	$ 3,339,470	6.00%	$ 200,368	0.00%	$ -	100.00%	$ 200,368	15.12%	$ 30,296	$ 30,296
	Support Services	$ 40,511,702	0.08%	$ 33,778	0.00%	$ -	100.00%	$ 33,778	15.12%	$ 5,107	$ 5,107
	TOTAL	**$ 49,829,685**		**$ 353,716**		**$ -**		**$ 353,716**		**$ 53,482**	**$ 53,482**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Time	H = G x Time	I = E + H
40. Tax Reporting & Planning	Tax Services (10049)	$ 6,412,807	96.70%	$ 6,201,396	1.00%	$ 62,014	1.50%	$ 93,021	1.00%	$ 926	$ 62,940
	CFO (10045)	$ 5,978,513	2.00%	$ 119,570	0.00%	$ -	0.00%	$ -	1.00%	$ -	$ -
	Support Services	$ 40,511,702	1.83%	$ 742,244	0.98%	$ 7,282	1.47%	$ 10,923	1.00%	$ 109	$ 7,391
	EPI Charge	$ 10,029,242	0.05%	$ 5,339	0.98%	$ 52	1.47%	$ 79	1.00%	$ 1	$ 53
	TOTAL	**$ 62,932,264**		**$ 7,068,549**		**$ 69,348**		**$ 104,023**		**$ 1,036**	**$ 70,384**

Service	Department	Primary Service Allocation									
		Loaded Department Budget	Time Allocation to Service	Primary Service Cost	EGD Time Allocation	Direct EGD Allocation	Common Time Allocation	Total Common Costs	Common Allocator	Common EGD Allocation	Total Primary Service Allocated To EGD
		A	B	C = A x B	D	E = C x D	F	G = F x C	Users	H = G x Users	I = E + H
43. Payroll Management	HR Employee Services (10036)	$ -	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	Support Services	$ 40,511,702	0.00%	$ -	0.00%	$ -	0.00%	$ -	25.61%	$ -	$ -
	TOTAL	**$ 40,511,702**		**$ -**		**$ -**		**$ -**		**$ -**	**$ -**

Attachment 1(b) to 2014 RCAM Report
SCHEDULE B - General Expense and Direct Charge Breakdown

Services	Total Budget	EGD Direct Allocation	Indirect Portion of Direct Charge: EI Direct Charge	Indirect Portion of Direct Charge: Allocator	Indirect Portion of Direct Charge: %	EGD Indirect Allocation	Total EGD Allocation
EGD EFS True Up							
Direct EFS Charge	$ (5,000,103)	$ (5,000,103)					$ (5,000,103)
Total EFS True Up	$ (5,000,103)	$ (5,000,103)					$ (5,000,103)
General Expenses							
Directors Fees and Expenses	$ 8,750,000		$ 8,750,000	FCER	15%	$ 1,275,750	$ 1,275,750
Directors Fees Credit - EGD		$ (52,000)					$ (52,000)
Total Directors Fees and Expenses	$ 8,750,000	$ (52,000)	$ 8,750,000			$ 1,275,750	$ 1,223,750
Depreciation - Risk Management System	$ 194,822	$ 25,132				$ -	$ 25,132
Depreciation - Enterprise Systems	$ 19,639,642	$ 3,392,008				$ -	$ 3,392,008
Total General Expenses	$ 28,584,464	$ 3,365,140	$ 8,750,000			$ 1,275,750	$ 4,640,890
Direct Charges							
Insurance Premiums	$ 59,202,595	$ 4,830,857				$ -	$ 4,830,857
Audit Fees	$ -	$ -	$ -	FCER	15%	$ -	$ -
EGD Stock Based Compensation	$ 9,225,003	$ 9,225,003				$ -	$ 9,225,003
Total Direct Charges	$ 68,427,598	$ 14,055,860	$ -			$ -	$ 14,055,860
Total Other Charges	**$ 92,011,959**	**$ 12,420,897**	**$ 8,750,000**			**$ 1,275,750**	**$ 13,696,647**

Attachment 1(b) to 2014 RCAM Report

SCHEDULE C - Breakdown of Return on Invested Capital

Net Book Value of Enbridge Inc. Assets (1)	Allocation Mechanism to EGD	Allocation Percentage	EGD Portion of EI Assets	Allowable Rate of Return	EGD Rate of Return Value
$ 34,563,478	FCER	15%	$ 5,039,355	9.36%	$ 471,684

Notes

(1) Does not include Work-In-Progress or Intangible Assets

Attachment 1(b) to 2014 RCAM Report

SCHEDULE D - Breakdown of EI Support Service Costs

Support Services	Total Budget
1. Air Travel for Company Personnel	$ 214,870
2. Budgeting & Forecasting	$ 4,671,351
3. Certification of Financial Reporting & Internal Controls	$ 1,409,573
4. Consolidation Accounting	$ 1,967,151
5. Corporate General Accounting	$ 3,698,687
6. Corporate Office Administration	$ 7,588,753
7. Environment, Health & Safety	$ 478,224
8. Financial Projects	$ 1,494,628
9. Financial Reporting	$ 7,552,590
10. HelpDesk, Network, Infrastructure & Hardware Support	$ -
11. Information System Support Applications	$ 6,729,903
12. Invoice Processing and Payment	$ 166,413
13. Corporate IT Program and Project Management	$ 220,074
14. Corporate IT System Management and Technical Support	$ 2,828,836
15. Payroll & Benefits Processing	$ 1,490,649
16. IFRS Service	$ -
Total Support Service Costs	**$ 40,511,702**

Attachment 2 to the 2014 RCAM Report

2014 vs. 2013 EGD RCAM Allocations Variance Analysis

2014 Individual ServiceThreshold: 12.4% (and >$50K). Greater than a 10% + Ontario CPI (2.4%) increase from 2013 to 2014, with a materiality threshold of >$50K

2014 Individual New Services: Service Schedules provided in Attachment 4

	Services / Direct Charges	Allocation to EGD 2014	Allocation to EGD 2013	$ Variance	% Variance	Explanation
Primary Services	Audit & Accounting Advice	$ 134,343	$ 158,418	$ (24,075)	-15.2%	
	Board of Directors Support	$ 707,990	$ 848,267	$ (140,277)	-16.5%	
	Business & Economic Financial Analysis	$ -	$ -	$ -	0%	
	Business Development	$ 303,345	$ 751,127	$ (447,782)	-59.6%	Lower support cost due to support services restructuring and reduced activities in Corporate Law
	Capital Market Financing & Access	$ 745,805	$ 1,029,508	$ (283,703)	-27.6%	Lower support cost due to support services restructuring and lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
	Cash Management & Banking	$ 249,517	$ 997,480	$ (747,963)	-75.0%	Reduction in activities performed by Treasury from the higher level in 2013 as noted in the 2013 explanation
	Consolidation and Planning System Technical Support (Khalix)	$ -	$ 275,164	$ (275,164)	N/A	Service removed due to reorganization of primary services within IT
	Corporate Compliance	$ 201,541	$ 290,362	$ (88,821)	-30.6%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
	Industry Relations & Corporate Social Responsibility (CSR)	$ -	$ 415,918	$ (415,918)	N/A	Service removed due to reorganization of primary services within PG&A
	Emerging Energy Technology Research	$ -	$ -	$ -	0%	
	Employee Development	$ 1,140,897	$ 1,318,597	$ (177,700)	-13.5%	
	Enterprise IT Program Management	$ -	$ 661,348	$ (661,348)	N/A	Service removed due to reorganization of primary services within IT
	Enterprise IT Strategy Planning & Management	$ -	$ 236,125	$ (236,125)	N/A	Service removed due to reorganization of primary services within IT
	Expense System Management & Technical Support (Oracle iExpense)	$ -	$ 240,347	$ (240,347)	N/A	Service removed due to reorganization of primary services within IT
	External Audit Coordination	$ 103,364	$ 207,076	$ (103,712)	-50.1%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
	Financial and Project Accounting System Technical Support (Oracle)	$ -	$ 517,170	$ (517,170)	N/A	Service removed due to reorganization of primary services within IT
	Gas Supply, Storage, and Transportation Strategy	$ -	$ -	$ -	0%	
	Government Relations	$ -	$ 48,971	$ (48,971)	N/A	Service removed due to reorganization of primary services within PG&A
	HRIS Program Management and Development	$ -	$ 3,487,053	$ (3,487,053)	N/A	Service removed due to reorganization of primary services between HR and IT
	Human Resource Advice	$ 312,301	$ 171,633	$ 140,668	82.0%	Increase in HR strategic development costs. This service has been provided in prior years however the costs were never allocated. The increase is due to the costs now being allocated.
	Insurance Claims Support, Strategy and Management	$ 199,281	$ 325,570	$ (126,289)	-38.8%	Lower activities following the renewal/restructuring of the insurance policies, lower support cost due to support services restructuring and lower cost base due to redistribution of SBC/STIP across a wider base
	Investor Services	$ 1,014,165	$ 1,099,448	$ (85,283)	-7.8%	
	Legal Advice	$ 487,544	$ 465,382	$ 22,162	4.8%	
	Planning, Management & Execution of Internal Audits	$ 359,369	$ 243,067	$ 116,301	47.8%	Restructuring of Internal Controls function from a support to a primary service
	Rate Regulated Entity Support	$ 209,479	$ 225,727	$ (16,248)	-7.2%	
	Records and Information Management	$ 1,054,087	$ 888,504	$ 165,583	18.6%	Significant increase in the number of users of Livelink (Enterprise Content Server) as a result of the email management rollout, partially offset by the restructuring of ECM to IT
	Risk Assessment and Management	$ 654,230	$ 865,435	$ (211,205)	-24.4%	Reduced enterprise risk activities and lower support cost due to support services restructuring
	Strategic Planning	$ 223,115	$ 253,073	$ (29,958)	-11.8%	
	Supply Chain Management	$ 53,482	$ 46,900	$ 6,582	14.0%	
	Tax Reporting & Planning	$ 70,384	$ 131,679	$ (61,295)	-46.5%	Reduced time spent on EGD
	Total Compensation and Benefits	$ 1,908,125	$ 2,399,292	$ (491,167)	-20.5%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure and lower support cost due to support services restructuring
	Employee and Labour Relations	$ 481,772	$ 588,542	$ (106,770)	-18.1%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
	Portal Suite Operations & Technical Support	$ -	$ 301,334	$ (301,334)	N/A	Service removed due to reorganization of primary services within IT
	Enterprise System Program and Project Management	$ 1,611,719	$ -	$ 1,611,719	N/A	New Service due to reorganization of IT and IT related services
	Enterprise Infrastructure Program and Project Management	$ 86,548	$ -	$ 86,548	N/A	New Service due to reorganization of IT and IT related services
	Enterprise System Management and Technical Support	$ 4,902,304	$ -	$ 4,902,304	N/A	New Service due to reorganization of IT and IT related services
	Enterprise Infrastructure Management and Technical Support	$ -	$ -	$ -	N/A	New Service due to reorganization of IT and IT related services
	IT Planning and Governance	$ 1,718,004	$ -	$ 1,718,004	N/A	New Service due to reorganization of IT and IT related services
	Brand Strategy & Community Investment Relations	$ 247,559	$ -	$ 247,559	N/A	New Service due to reorganization PG&A services
	Government Relations & CSR	$ 268,319	$ -	$ 268,319	N/A	New Service due to reorganization PG&A services
	Payroll Services	$ -	$ -	$ -	N/A	New Service due to centralization of service at Corporate EI
	Safety and Process Safety	$ -	$ -	$ -	N/A	New Service - new business requirement
	Total Service Charges	**$ 19,448,587**	**$ 19,488,516**	**$ (39,929)**	**-0.2%**	
General Expenses & Direct Charges	Direct EFS Charge (Credit)	$ (5,000,103)	$ (2,129,052)	$ (2,871,051)	134.9%	As EFS increases the enterprise costs that are budgeted at EGD, there is a corresponding higher credit to EGD to reflect the usage of service
	Directors Fees & Expenses	$ 1,223,750	$ 1,089,370	$ 134,380	12.3%	
	Depreciation - Risk Management System	$ 25,132	$ 133,581	$ (108,449)	-81.2%	
	Depreciation - Enterprise Systems	$ 3,392,008	$ -	$ 3,392,008	N/A	New assets requirements to implement the FRP roadmap and as a result of the centralization of the IT infrastructure systems at Corporate
	Insurance Premiums	$ 4,830,857	$ 5,652,239	$ (821,382)	-14.5%	Continues to see cost savings in 2014 post restructuring of insurance policies
	BU Stock Based Compensation Charge	$ 9,225,003	$ 10,657,647	$ (1,432,645)	-13.4%	Reduction is a function of the number of participants and stock prices
	Total Direct Charges	**$ 13,696,647**	**$ 15,403,785**	**$ (1,707,139)**	**-11.1%**	
	Return on Invested Capital	**$ 471,684**	**$ 353,189**	**$ 118,495**	**33.5%**	
	Total EGD Allocation	**$ 33,616,917**	**$ 35,245,490**	**$ (1,628,573)**	**-4.6%**	

Attachment 3 to the 2014 RCAM Report
Enbridge RCAM Allocation Trend - 2007 To 2014
($000)

	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 & adjusted by MNP's recommendation)	2013 (Forecast Filed in EB-2011-0354)	2013 (Calculated Using the Board-approved RCAM methodology - preliminary Filed in EB-2012-0459)	2013 (As Approved by Enbridge under the ISA)	2014 (As Approved by Enbridge under the ISA)
Primary Services	Audit & Accounting Advice	$ 86,095	$ 80,559	$ 123,457	$ 176,276	$ 202,937	$ 91,270	$ 93,278	$ 158,418	$ 158,418	$ 134,343
	Board of Directors Support	$ 511,270	$ 548,758	$ 524,382	$ 653,787	$ 512,237	$ 769,368	$ 785,892	$ 848,267	$ 848,267	$ 707,990
	Business & Economic Financial Analysis	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Business Development	$ 652,513	$ 648,678	$ 442,656	$ 440,041	$ 533,671	$ 736,918	$ 753,039	$ 751,127	$ 751,127	$ 303,345
	Capital Market Financing & Access	$ 681,246	$ 704,394	$ 680,419	$ 857,868	$ 986,346	$ 991,870	$ 1,013,640	$ 1,029,508	$ 1,029,508	$ 745,805
	Cash Management & Banking	$ 222,036	$ 228,425	$ 268,955	$ 346,810	$ 388,868	$ 481,073	$ 491,656	$ 997,480	$ 997,480	$ 249,517
	Consolidation and Planning System Technical Support (Khalix)	$ 375,868	$ 411,470	$ 424,221	$ 492,550	$ 606,411	$ 245,089	$ 249,486	$ 275,164	$ 275,164	$ -
	Corporate Compliance	$ 99,725	$ 79,694	$ 103,385	$ 129,802	$ 134,323	$ 197,202	$ 201,540	$ 290,362	$ 290,362	$ 201,541
	Industry Relations and Corporate Social Responsibility (CSR)	$ 245,307	$ 184,961	$ 310,317	$ 399,487	$ 465,205	$ 384,365	$ 392,741	$ 415,918	$ 415,918	$ -
	Emerging Energy Technology Research	$ 146,966	$ 73,533	$ 55,901	$ 74,371	$ 47,593	$ -	$ -	$ -	$ -	$ -
	Employee Development	$ 255,425	$ 326,279	$ 547,313	$ 803,140	$ 1,200,754	$ 1,245,623	$ 1,273,025	$ 1,318,597	$ 1,318,597	$ 1,140,897
	Enterprise IT Program Management	$ 149,002	$ 198,557	$ 183,664	$ 413,230	$ 389,669	$ 868,494	$ 887,579	$ 661,348	$ 661,348	$ -
	Enterprise IT Strategy Planning & Management	$ 550,749	$ 534,684	$ 446,745	$ 594,422	$ 467,282	$ 624,115	$ 637,845	$ 236,125	$ 236,125	$ -
	Expense System Management & Technical Support (Oracle iExpense)	$ 119,526	$ 131,407	$ 147,714	$ 167,015	$ 239,394	$ 95,490	$ 97,384	$ 240,347	$ 240,347	$ -
	External Audit Coordination	$ 43,174	$ 42,501	$ 56,582	$ 76,248	$ 63,299	$ 103,399	$ 105,673	$ 207,076	$ 207,076	$ 103,364
	Financial and Project Accounting System Technical Support (Oracle)	$ 320,766	$ 244,535	$ 256,641	$ 254,570	$ 261,570	$ 352,161	$ 358,097	$ 517,170	$ 517,170	$ -
	Gas Supply, Storage, and Transportation Strategy	$ 571,267	$ 525,390	$ 390,843	$ 231,134	$ -	$ -	$ -	$ -	$ -	$ -
	Government Relations	$ 119,234	$ 165,187	$ 47,715	$ 120,509	$ 34,848	$ 44,917	$ 45,895	$ 48,971	$ 48,971	$ -
	Human Resources Information Systems (HRIS)	$ 689,995	$ 802,393	$ 742,447	$ 1,545,942	$ 2,169,992	$ 2,897,597	$ 2,961,312	$ 3,487,053	$ 3,487,053	$ -
	Human Resource Advice	$ 101,190	$ 92,772	$ 168,134	$ 271,938	$ 354,073	$ 201,779	$ 206,184	$ 171,633	$ 171,633	$ 312,301
	Insurance Claims Support	$ 2,887	$ 5,602	$ 4,402	$ 6,301	$ 7,145	$ -	$ -	$ -	$ -	$ -
	Insurance Strategy and Management	$ 84,730	$ 69,689	$ 79,418	$ 120,927	$ 119,312	$ 108,240	$ 109,912	$ 325,570	$ 325,570	$ 199,281
	Investor Services	$ 994,024	$ 843,304	$ 585,153	$ 685,330	$ 811,451	$ 883,837	$ 903,044	$ 1,099,448	$ 1,099,448	$ 1,014,165
	Legal Advice	$ 303,414	$ 365,223	$ 433,306	$ 749,045	$ 572,710	$ 514,396	$ 525,600	$ 465,382	$ 465,382	$ 487,544
	Planning, Management & Execution of Internal Audits	$ 82,338	$ 87,693	$ 187,727	$ 228,607	$ 185,494	$ 191,528	$ 195,741	$ 561,368	$ 243,067	$ 359,369
	Rate Regulated Entity Support	$ 328,451	$ 225,379	$ 97,621	$ 128,419	$ 147,295	$ 253,904	$ 259,490	$ 225,727	$ 225,727	$ 209,479
	Records and Information Management	$ 456,875	$ 623,795	$ 494,550	$ 298,336	$ 304,392	$ 538,352	$ 550,195	$ 888,504	$ 888,504	$ 1,054,087
	Risk Assessment and Management	$ 541,913	$ 623,959	$ 686,348	$ 882,571	$ 1,062,095	$ 878,461	$ 897,681	$ 865,435	$ 865,435	$ 654,230
	Strategic Planning	$ 167,834	$ 183,816	$ 160,673	$ 194,768	$ 253,879	$ 327,890	$ 335,020	$ 253,073	$ 253,073	$ 223,115
	Supply Chain Management	$ 19,504	$ 9,394	$ 21,249	$ 24,088	$ 30,414	$ 39,706	$ 40,580	$ 46,900	$ 46,900	$ 53,482
	Tax Reporting & Planning	$ 10,196	$ 13,238	$ 14,512	$ 21,630	$ 24,894	$ 55,308	$ 56,525	$ 131,679	$ 131,679	$ 70,384
	Total Compensation and Benefits	$ 865,843	$ 887,721	$ 850,234	$ 1,313,100	$ 1,410,246	$ 1,781,809	$ 1,820,969	$ 2,399,292	$ 2,399,292	$ 1,908,125
	Employee and Labour Relations	$ 253,530	$ 299,985	$ 348,384	$ 458,995	$ 552,430	$ 478,201	$ 488,722	$ 588,542	$ 588,542	$ 481,772
	Portal Suite Operations & Technical Support	$ 259,283	$ 263,057	$ 236,449	$ 156,062	$ 172,685	$ 330,881	$ 338,160	$ 301,334	$ 301,334	$ -
	Enterprise System Program and Project Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,611,719
	Enterprise Infrastructure Program and Project Management	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 86,548
	Enterprise System Management and Technical Support	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,902,304
	Enterprise Infrastructure Management and Technical Support	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	IT Planning and Governance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,718,004
	Brand Strategy & Community Investment Relations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 247,559
	Government Relations & CSR	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 268,319
	Payroll Services	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Safety and Process Safety	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Service Charges	**$ 10,312,177**	**$ 10,526,035**	**$ 10,121,518**	**$ 13,317,317**	**$ 14,712,914**	**$ 16,713,243**	**$ 17,075,905**	**$ 19,806,817**	**$ 19,488,516**	**$ 19,448,587**
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)	$ (2,129,052)	$ (2,129,052)	$ (5,000,103)
	Directors Fees & Expenses	$ 501,718	$ 475,364	$ 426,433	$ 517,905	$ 545,235	$ 744,819	$ 761,205	$ 1,141,370	$ 1,089,370	$ 1,223,750
	Depreciation - Risk Management System	$ 24,512	$ 72,919	$ 74,436	$ 13,827	$ 68,965	$ 64,951	$ 64,951	$ 133,581	$ 133,581	$ 25,132
	Depreciation - Enterprise Systems	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,392,008
	Insurance Premiums	$ 4,905,300	$ 4,096,200	$ 4,571,600	$ 5,179,873	$ 4,338,678	$ 8,483,868	$ 8,483,868	$ 5,652,239	$ 5,652,239	$ 4,830,857
	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	$ 10,657,647	$ 10,657,647	$ 9,225,003
	Total Direct Charges	**$ 7,449,788**	**$ 8,349,277**	**$ 10,368,836**	**$ 10,504,652**	**$ 11,585,047**	**$ 14,528,083**	**$ 14,710,552**	**$ 15,455,785**	**$ 15,403,785**	**$ 13,696,647**
	Return on Invested Capital	**$ 300,553**	**$ 198,909**	**$ 625,604**	**$ 443,159**	**$ 369,543**	**$ 368,896**	**$ 357,703**	**$ 353,189**	**$ 353,189**	**$ 471,684**
	Total Enbridge Allocation	**$ 18,062,517**	**$ 19,074,221**	**$ 21,115,958**	**$ 24,265,127**	**$ 26,667,504**	**$ 31,610,223**	**$ 32,144,160**	**$ 35,615,791**	**$ 35,245,490**	**$ 33,616,917**

15. Enterprise System Program and Project Management

Service Description	
Service Definition:	The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide.

Services Identified by Department	<u>**CIO Department**</u>
	The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The CIO Department is responsible for oversight of all IT activities with a specific focus on ensuring activities are aligned with the overall strategic priorities.
	
	Examples of activities related to the provision of the service include:
	• Set the annual strategic priorities for IT System Program and Project Management
	• Provide System Program and Project Management oversight to large, high risk or complex initiatives
	• Ensure appropriate governance for IT System Program and Project Management
	
	<u>**IT Compliance Systems Department**</u>
	The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The Compliance Systems supports the overall audit, IT security, and health & safety requirements of the business. The IT Compliance Systems Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of the Compliance Management systems, including its ongoing enhancements.
	
	Examples of activities related to the provision of the service include:
	• Manage client relationships and communications
	• Lead the strategic planning process in relation to efficiency and effectiveness of IT Compliance Systems applications
	• Support & Maintenance
	  o System administration
	  o User support, maintenance & security
	  o User training & communication
	  o Change management
	• Reporting & Analysis
	  o Provision of standard reports
	  o Ad hoc report generation / queries
	  o Augment, add, or remove reporting requirements
	• Technical Support
	  o Interface management
	  o System configurations, customization or enhancements
	  o Release management
	  o Manage development life cycle
	  o Monitor system performance
	• Vendor Management
	  o Negotiate, monitor and manage vendor contract
	  o Negotiate, monitor and manage IT outsourcing relationships
	  o Research and monitor emerging technologies

IT Carbon Data Management (CDM) Systems Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The CDM systems support the overall emissions, environmental compliance and operational incident reporting requirements of the business. The IT CDM Systems Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of the CDM systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IT Compliance Systems applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Enterprise Financial Systems (EFS) Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT EFS supports the overall financial management requirements of the business by providing project management support. The IT EFS Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of EFS, including its ongoing enhancements.

Examples of activities related to the provision of this service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User (incl. super user / power user) training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements

- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Master-file maintenance
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Enterprise Content Management (ECM) Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT ECM Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of the ECM systems, including its ongoing enhancements. The systems portfolio includes Livelink, EnCase and Matter Compass (the Portfolio).

Examples of activities related to the provision of this service include:

- In partnership with technology users, develop and maintain folder structure following guiding principles as set by ECM and Records Management
- Administer the records management module of Livelink
- Maintain records retention schedule links to folder structure
- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IT ECM applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT HRIS Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT HRIS Systems Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of the Human Resources systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of HRIS applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Identity and Access Management (IAM) Systems Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT IAM Systems Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of the IAM systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IAM applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Marketing and Risk Management (MRM) Systems Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT MRM Systems support the overall commodity and financial risk management requirements of the business by providing project management support. The IT MRM Systems Department performs all activities related to managing and delivering programs and projects required for the day-to-day operations of the MRM systems, including its enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of MRM applications
- Support & Maintenance
    - System administration
    - User support, maintenance & security
    - User training & communication
    - Change management
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation / queries
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships
    - Research and monitor emerging technologies

IT Planning and Governance Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT Planning and Governance Department is responsible for ensuring that effective financial, resource and project planning processes and tools exist and that they are used appropriately.

Examples of activities related to the provision of the service include:

- Development of program/project management policies and procedures for implementing and managing enterprise wide IT systems
- Research new alternatives to conducting business through different service approaches (i.e. IT outsourcing)
- Monitoring ongoing system projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management
- Run post-project reviews on IT system projects to assess and learn from the process
- Provide financial reporting on IT system project performance to help Enbridge Inc. and its affiliates understand the financial specifics for all enterprise projects.
- Perform threat and risk assessment activities for all IT system projects to

make sure security risks are identified, mitigate and appropriately managed.

IT Public Web Systems Department

The Enterprise System Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the services provided by the systems that are used enterprise-wide. The IT Public Web Systems Department performs all activities related to managing and delivering of programs and projects required for the day-to-day operations of the Public Web systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of Public Web applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

Service Recipient: Mr. Biju Misra, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$211,120
IT Compliance Systems	$0
IT Carbon Data Management (CDM)	$0
IT Enterprise Financial Systems (EFS)	$182,003
IT Enterprise Content Management (ECM)	$575,009
IT HRIS	$263,072
IT Identity and Access Management (IAM)	$322,502
IT Marketing and Risk Management (MRM)	$58,013
IT Planning and Governance	$0
IT Public Web Systems	$0
Total	$1,611,719

Expected Deliverables

- Implement and integrate enterprise information technology projects for the benefit of EGD
- Align technology to EGD and short and long term operational needs
- Provide status reports on enterprise Infrastructure technology projects

13. Enterprise Infrastructure Program and Project Management

Service Description	
Service Definition:	The Enterprise Infrastructure Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the technical computing infrastructure such as the wide area network.
Services Identified by Department	**CIO Department** The Enterprise Infrastructure Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the technical computing infrastructure such as the wide area network. The CIO Department is responsible for oversight of all IT activities with a specific focus on ensuring activities are aligned with the overall strategic priorities. Examples of activities related to the provision of the service include: • Set the annual strategic priorities for IT infrastructure program and project management • Provide oversight to the program and project management of large, high risk or complex initiatives • Ensure appropriate governance for IT infrastructure program and project management initiatives **IT Planning and Governance Department** The Enterprise Infrastructure Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the technical computing infrastructure such as the wide area network. The IT Planning and Governance Department is responsible for ensuring that effective financial, resource and project planning processes and tools exist and that they are used appropriately. Examples of activities related to the provision of the service include: • Development of program/project management policies and procedures for implementing and managing enterprise wide IT infrastructure • Research new alternatives to conducting business through different service approaches (i.e. IT outsourcing) • Monitoring ongoing IT infrastructure projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management • Run post-project reviews on IT infrastructure projects to assess and learn from the process • Provide financial reporting on enterprise IT infrastructure project performance to help Enbridge Inc. and its affiliates understand the financial specifics for all enterprise projects. • Perform threat and risk assessment activities for all IT infrastructure projects to make sure security risks are identified, mitigated and appropriately managed. **IT Management Department** The Enterprise Infrastructure Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the technical computing infrastructure such as the wide area network. The IT Management Department is responsible for ensuring that the portfolio of program and project activities for Enterprise Systems and Infrastructure Shared Services is appropriately planned, administered and reported upon.

Examples of activities related to the provision of the service include:

- Lead the annual program and project budget development process
- Develop processes and templates for the monthly project health and financial reporting cycles
- Ensure all proper project management methodologies are followed

IT Security Operations Department

The Enterprise Infrastructure Program and Project Management service includes all activities related to managing and delivering programs and projects required to evolve and grow the technical computing infrastructure such as the wide area network. The Security Operations Department supports this by developing project plans, allocating resources, and coordinating the execution of IT Security Infrastructure projects.

Examples of activities related to the provision of the service include:

- Develop project plans
- Provide stakeholders with monthly project health updates, as well as project financial reporting
- Allocate and coordinate project resources to execute project plans

Service Recipient: Mr. Biju Misra, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$86,548
IT Planning and Governance	$0
IT Management	$0
IT Security Operations	$0
Total	$86,548

Expected Deliverables

- Implement and integrate enterprise information technology projects for the benefit of EGD
- Align technology to EGD and short and long term operational needs
- Provide status reports on enterprise Infrastructure technology projects
- Expertise for individual projects and the development and ongoing maintenance of the PM methodology.

Quantity and Quality of Service

- Effective, low cost IT implementations
- Delivered on time and budget with established requirements
- Ensuring a robust PM methodology to increase the likelihood of project delivery on time, on budget and meeting quality specifications.
- Ensuring projects follow a rigorous documentation process.
- Update EGD Management with alternatives that could benefit ratepayers.
- Ensuring enterprise projects that EGD benefits from are monitored appropriately and have the necessary controls and quality checks in place.

Authorized Signature

Mr. Biju Misra
Director Information Technology
Enbridge Gas Distribution

Dec 15/2014
Date

14. Enterprise System Management and Technical Support

Service Description	
Service Definition:	The Enterprise IT Strategy Planning and System Management and Technical Support service governs includes all activities related to managing day-to-day operations of the development of enterprise wide strategies, policies and standards for information technologies. systems such as Oracle Financial System.
Services Identified by Department	**CIO Department** The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The CIO Department is responsible for oversight of all IT activities with a specific focus on ensuring activities are aligned with the overall strategic priorities. Examples of activities related to the provision of this service include: • Set the annual strategic priorities for IT System Management and Technical Support • Provide oversight to large, high risk or complex System Management and Technical Support • Ensure appropriate governance for IT System Management and Technical Support **Corporate Human Resources Department** The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The Corporate Human Resources Department supports this service by providing HR user expertise and developing the required HR processes and controls. Examples of activities related to the provision of the service include: • Work with affiliates to determine immediate and long-term HRIS and other HR technology requirements. • Keep appraised of HRIS service offerings in the HRIS marketplace in North America. • Keep appraised of PeopleSoft offerings. • Work with affiliates to match requirements and available services. • Provide expertise required to support the development of business cases for the modifying, expanding or acquiring of new HRIS and other HR technology functionality. • Work with IT HRIS development and business unit human resource staff to plan, execute and implement modifications, expansions or new HRIS and other HR technology functionality. • Work with affiliate human resource staff to train users. • Work with affiliate human resource staff to ensure maximum benefit is realized from HRIS investments. • Conduct research on additional HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives • Develop business case, project charter, project plan and other required project documentation; including securing project approval • Organize and coordinate non-IT team resources (both internal and external resources) • Develop business process and non-IT related training materials and

provide training to Enbridge Inc. and its affiliates
- Advise on change management issues and communication plans
- Provide resources to other enterprise projects
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation
  - Augment, add, or remove reporting requirements

HR Enterprise Business Solutions Department

The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The HR Enterprise Business Solutions Department supports this service by conducting initial business requirements gathering, functional design, data reporting, technical education and post go-live support, providing HR user the functional expertise to developing the required HR processes and controls.

Examples of activities related to the provision of the service include:
- Work with affiliates to determine immediate and long-term IT HRIS requirements, and how it ties back to the HR Strategy
- Keep appraised of IT HRIS service offerings in the IT HRIS marketplace in North America (including PeopleSoft)
- Work with affiliates to match business requirements and available services.
- Provide expertise required to support the development of business cases for the modifying, expanding or acquiring of new IT HRIS functionality.
- Work with IT HRIS development and business unit human resource staff to plan, execute and implement modifications, expansions or new IT HRIS functionality.
- Design training materials and work with affiliate human resource staff to train users.
- Work with affiliate human resource staff to ensure maximum benefit is realized from IT HRIS investments.
- Conduct research on additional IT HRIS modules and other related matters for the purpose of improving support of business operational and strategic objectives
- Work with stakeholders to identify required enhancements or changes to existing systems.
- Develop testing plans for any new addition to technology
- Maintain set-up tables to ensure that data is stored appropriately to deliver data to make decisions
- Provide resources to other enterprise projects
- Support & Maintenance
  - Functional trouble shooting
  - User support
  - Provide user (incl. super user / power user) training materials & communication
  - Change management
  - Ad-hoc and on-going reporting requests
  - Business requirements gathering for new functionality and enhancements to existing technology

IT Compliance Systems Department

The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The Compliance Systems supports the overall audit, IT security, and health & safety requirements of the business. The IT Compliance Systems Department performs all activities related to managing the day-to-day operations of the Compliance Management systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IT Compliance Systems applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Carbon Data Management (CDM) Systems Department

The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The CDM systems support the overall emissions, environmental compliance and operational incident reporting requirements of the business. The IT CDM Systems Department performs all activities related to managing the day-to-day operations of the CDM systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IT CDM applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management

- Negotiate, monitor and manage vendor contract
- Negotiate, monitor and manage IT outsourcing relationships
- Research and monitor emerging technologies

IT Enterprise Financial Systems (EFS) Department

The Enterprise System Management and Technical Support service includes all activities related to managing day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The IT EFS supports the overall financial management requirements of the business by providing systems, tools, and technical support. The IT EFS Department performs all activities related to managing the day-to-day operations of the EFS applications, its ongoing enhancements.

Examples of activities related to the provision of this service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of EFS applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User (incl. super user / power user) training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Master-file maintenance
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Enterprise Content Management (ECM) Department

The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The IT ECM Department performs all activities related to managing the day-to-day operations of the ECM systems, including its ongoing enhancements. The systems portfolio that supports the Records and Information Management service includes Livelink, EnCase and Matter Compass (the Portfolio).

Examples of activities related to the provision of this service include:

- In partnership with technology users, develop and maintain folder structure following guiding principles as set by ECM and Records Management
- Administer the records management module of Livelink
- Maintain records retention schedule links to folder structure
- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IT ECM applications
- Support & Maintenance

-
    - System administration
    - User support, maintenance & security
    - User training & communication
    - Change management
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation / queries
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships
    - Research and monitor emerging technologies

IT HRIS Department

The Enterprise System Management and Technical Support service includes all activities related to managing day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The IT HRIS Systems Department performs all activities related to managing the day-to-day operations of the Human Resources systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of HRIS applications
- Support & Maintenance
    - System administration
    - User support, maintenance & security
    - User training & communication
    - Change management
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation / queries
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships
    - Research and monitor emerging technologies

IT Identity and Access Management (IAM) Systems Department

The Enterprise System Management and Technical Support service includes all activities related to managing day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The IT IAM Systems Department performs all activities related to managing the day-to-day operations of IAM systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of IAM applications
- Support & Maintenance
    - System administration
    - User support, maintenance & security
    - User training & communication
    - Change management
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation / queries
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships
    - Research and monitor emerging technologies

IT Marketing and Risk Management (MRM) Systems Department

The Enterprise System Management and Technical Support service includes all activities related to managing day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The IT MRM Systems support the overall commodity and financial risk management requirements of the business by providing system management and technical support. Department performs all activities related to managing the day-to-day operations of the MRM systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of MRM applications
- Support & Maintenance
    - System administration
    - User support, maintenance & security
    - User training & communication
    - Change management
- Reporting & Analysis
    - Provision of standard reports
    - Ad hoc report generation / queries
    - Augment, add, or remove reporting requirements
- Technical Support
    - Interface management
    - System configurations, customization or enhancements
    - Release management
    - Manage development life cycle
    - Monitor system performance
- Vendor Management
    - Negotiate, monitor and manage vendor contract
    - Negotiate, monitor and manage IT outsourcing relationships

- Research and monitor emerging technologies

IT Public Web Systems Department

The Enterprise System Management and Technical Support service includes all activities related to managing day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The IT Public Web Systems Department performs all activities related to managing the day-to-day operations of the Public Web systems, including its ongoing enhancements.

Examples of activities related to the provision of the service include:

- Manage client relationships and communications
- Lead the strategic planning process in relation to efficiency and effectiveness of Public Web applications
- Support & Maintenance
  - System administration
  - User support, maintenance & security
  - User training & communication
  - Change management
- Reporting & Analysis
  - Provision of standard reports
  - Ad hoc report generation / queries
  - Augment, add, or remove reporting requirements
- Technical Support
  - Interface management
  - System configurations, customization or enhancements
  - Release management
  - Manage development life cycle
  - Monitor system performance
- Vendor Management
  - Negotiate, monitor and manage vendor contract
  - Negotiate, monitor and manage IT outsourcing relationships
  - Research and monitor emerging technologies

IT Security Operations Department

The Enterprise System Management and Technical Support service includes all activities related to managing the day-to-day operations of all Enterprise Systems (such as Oracle eBusiness Suite, PeopleSoft HCM and Livelink Records Management). The Security Operations Department supports this by providing guidance to the Identity and Access Management activities, as well as providing remote access, security monitoring, and security architecture/disaster recovery services.

Examples of activities related to the provision of the service include:

- Configuring remote access
- Providing security architecture guidance
- Developing disaster recovery plans
- Monitoring enterprise systems for security breaches
- Securing access to enterprise systems

Service Recipient: Mr. Biju Misra, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
CIO	$114,542

Corporate Human Resources	$265,172
HR Enterprise Business Solutions	$652,018
IT Compliance Systems	$0
IT Carbon Data Management (CDM)	$0
IT Enterprise Financial Systems (EFS)	$427,212
IT Enterprise Content Management (ECM)	$1,799,369
IT HRIS	$1,410,446
IT Identity and Access Management (IAM)	$162,259
IT Marketing and Risk Management (MRM)	$55,047
IT Public Web Systems	$16,239
IT Security Operations	$0
Total	$4,902,304

Expected Deliverables

- Implement and integrate enterprise information technology projects for the benefit of EGD
- Align technology to EGD and short and long term operational needs
- Provide status reports on enterprise Infrastructure technology projects
- Expertise for individual projects and the development and ongoing maintenance of the PM methodology.

Quantity and Quality of Service

- Effective, low cost IT implementations
- Delivered on time and budget with established requirements
- Ensuring a robust PM methodology to increase the likelihood of project delivery on time, on budget and meeting quality specifications.
- Ensuring projects follow a rigorous documentation process.
- Update EGD Management with alternatives that could benefit ratepayers.
- Ensuring enterprise projects that EGD benefits from are monitored appropriately and have the necessary controls and quality checks in place.

Authorized Signature

Mr. Biju Misra
Director Information Technology
Enbridge Gas Distribution

Dec 19/2014
Date

	• Expertise for individual projects and the development and ongoing maintenance of the PM methodology.
Quantity and Quality of Service	
	• Effective, low cost IT implementations • Delivered on time and budget with established requirements • Ensuring a robust PM methodology to increase the likelihood of project delivery on time, on budget and meeting quality specifications. • Ensuring projects follow a rigorous documentation process. • Update EGD Management with alternatives that could benefit ratepayers. • Ensuring enterprise projects that EGD benefits from are monitored appropriately and have the necessary controls and quality checks in place.
Authorized Signature	
	Mr. Biju Misra Director Information Technology Enbridge Gas Distribution Dec 14/2014 Date

22. IT Planning and Governance

Service Description	
Service Definition:	The IT Planning and Governance service includes all activities related to ensuring that IT is effectively planned and governed (for instance IT Security Risk Management, IT Enterprise Architecture and IT financial and resource planning).
Services Identified by Department	**<u>Executive VP Law Department</u>** The IT Planning and Governance service includes all activities related to ensuring that IT is effectively planned and governed (for instance IT Security Risk Management, IT Enterprise Architecture and IT financial and resource planning). The Executive VP Law Department supports this service by providing senior leadership and advice regarding the corporate information technology strategy and its alignment with the Enbridge and affiliate long-range plans. Examples of activities related to the provision of the service include: • Responsible for the review and approval of information technology project concepts and IT project expenditure • Responsible for IT security and the interfaces around enterprise-wide applications, for example, EFS, HRIS and the intranet portals • Responsible for structure and usage of intranet portals related to human resource issues and internal communication issues (including e-Link, Peoplesoft and Markview) **<u>CIO Department</u>** The IT Planning and Governance service includes all activities related to ensuring that IT is effectively planned and governed (for instance IT Security Risk Management, IT Enterprise Architecture and IT financial and resource planning). The CIO Department is responsible for oversight of all IT activities with a specific focus on ensuring activities are aligned with the overall strategic priorities. Examples of activities related to the provision of the service include: • Set the annual strategic priorities for IT Planning and Governance • Provide overall oversight to large, high risk or complex IT infrastructure/ system Program & Project Management and Technical Support initiatives • Ensure appropriate governance for IT Planning and Governance **<u>IT Architecture Department</u>** The IT Planning and Governance service includes all activities related to ensuring that IT is effectively planned and governed (for instance IT Security Risk Management, IT Enterprise Architecture and IT financial and resource planning). The IT Architecture Department provides a holistic view of the enterprise strategy, processes, information and IT assets to ensure that the business and IT are aligned and that the value of the investment in information technology is maximized. Examples of activities related to the provision of the service include: • Facilitate annual technical road mapping sessions • Provide architectural guidance to system plans • Provide detailed technical oversight and consulting to projects and programs • Responsible for ensuring that enterprise systems are safe and secure and built on an appropriate technical architecture which will meet the enterprise's needs in both the short and long term **<u>IT Planning and Governance Department</u>**

The IT Planning and Governance service includes all activities related to ensuring that IT is effectively planned and governed (for instance IT Security Risk Management, IT Enterprise Architecture and IT financial and resource planning). The IT Planning and Governance Department is responsible for ensuring that effective financial, resource and project planning processes and tools exist and that they are used appropriately.

Examples of activities related to the provision of the service include:

- Develop program/project management policies and procedures for implementing and managing the overall enterprise wide IT operations
- Research new alternatives to conducting business through different service approaches (i.e. IT outsourcing)
- Monitor the overall IT operations ongoing projects to maintain alignment with strategic and project objectives; including the provision of progress reports to senior management
- Run post-project reviews on the overall IT operations projects to assess and learn from the process
- Provide financial reporting on the overall IT operations project performance to help Enbridge Inc. and its affiliates understand the financial specifics for all enterprise projects.

IT Security Department

The IT Planning and Governance service includes all activities related to ensuring that IT is effectively planned and governed (for instance IT Security Risk Management, IT Enterprise Architecture and IT financial and resource planning). The IT Security Department is responsible for IT security governance and planning, maintenance of a core set of security policies, detection of security threats and vulnerabilities, assessment of security risks, managing IT Risk Management policy compliance, planning and execution of security awareness program.

Examples of activities related to the provision of the service include:

- Develop and administer the threat and risk assessment program.
- Develop and administer the Enterprise Vulnerability Assessment Service.
- Participate in IT Strategic Planning to ensure long term plans reflect the evolving threat landscape.

Service Recipient: Mr. Biju Misra, Director Information Technology, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Executive VP Law	$80,771
CIO	$350,382
IT Architecture	$536,004
IT Planning and Governance	$519,261
IT Security	$231,586
Total	$1,718,004

Expected Deliverables

- Support EGD staff with legal research, insights and knowledge leveraging the collective expertise of Enbridge Inc.
- Facilitate the acquisition of cost effective external legal services through the negotiation of volume discounts with national law firms utilized by EGD.

Quantity and Quality of Service

- On demand access to expertise and reliable legal advice and knowledge

	• Effective and current legal research, reporting and access to up to date legal precedents.
Authorized Signature	
	Mr. Biju Misra Director, Information Technology Enbridge Gas Distribution Dec 14 2014 Date

3. Brand Strategy & Community Investment Relations

Service Description

Service Definition:

The Brand Strategy & Community Investment Relations service helps communicate and share EGD brand purpose, tying it to our overall EGD corporate strategy and vision.

Services Identified by Department

Enterprise Communications & Community Partners Department

The Brand Strategy & Community Investment Relations service helps communicate and share EGD brand purpose, tying it to our overall EGD corporate strategy and vision. The Enterprise Communications & Community Partners Department supports this service by providing strategy direction and guidance to EGD.

Examples of activities related to the provision of the service include:

Brand Strategy

- Define brand purpose, strategy and implementation.
- Support brand strategy executions.

Community Investment Relations

- Define broad Community Investment focus areas
- Highlight EGD sponsorship and donations in corporate reports
- Identifies trends and activities, and creates strategic collaborative community related relationships and partnerships through liaising with peer corporations regularly.
- Provide support for the Volunteer in Partnership program tracking

Service Recipient:

Mr. Jamie Milner, Vice-President Market Development and Customer Care, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
Enterprise Communications & Community Partners	$247,559
Total	$247,559

Expected Deliverables

- Brand strategy, visual representation and defined characteristics
- Templates to reinforce the brand
- Community Investment portfolio structure

Quantity and Quality of Service

- Favourable public perception of EGD, as measured by IPSOS survey

Authorized Signature

Mr. Jamie Milner
Vice-President Market Development
and Customer Care
Enbridge Gas Distribution

Dec. 15/14
Date

18. Government Relations & Corporate Social Responsibility (CSR)

<table>
<tr><th colspan="2">Service Description</th></tr>
<tr><td>Service Definition:</td><td>The Government Relations & CSR service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees, and ensures alignment of corporate social responsibility initiatives, strategy and policies to company annual and long-range strategic plans.</td></tr>
<tr><td>Services Identified by Department</td><td><u>People and Partners Department</u>
The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees, and ensures alignment of corporate social responsibility initiatives, strategy and policies to company annual and long-range strategic plans. The People and Partners Department supports this service by overseeing the delivery of Aboriginal and Stakeholder Relations, Public Affairs and Community Relations, Government Affairs, and CSR.

Examples of activities related to the provision of the service include:
Development, implementation and monitoring of the Corporate Social Responsibility programs and initiatives.
<u>Public, Government and Aboriginal Affairs Department</u>
The Government Relations service ensures EGD's interests are heard by government (federal, Ontario and municipal) officials, departments and committees, and ensures alignment of corporate social responsibility initiatives, strategy and policies to company annual and long-range strategic plans. The Public, Government and Aboriginal Affairs Department supports this service by providing expertise in the area of Aboriginal and Stakeholder Relations, Public Affairs and Community Relations, Government Affairs, and CSR.

Examples of activities related to the provision of the service include:

Aboriginal and Stakeholder Relations
Provide internal and external resources to support government affairs activities.
Provide a stakeholder and aboriginal consultation program designed to help EGD secure regulatory approvals and keep its commitment to continued stakeholder engagement through the construction and in-service of all construction projects.
Manage issues and concerns with the objective of mitigating or resolving claims of project related impacts asserted by Aboriginal communities.
Support Environment in completing traditional use studies for affected First Nations and Metis communities.
Stakeholder Relations is responsible for notification activities as well as consultation with Municipalities, other local authorities and community groups in proximity to our operations
Manage Aboriginal and Stakeholder Relations commitments.
Manage process by which contact records documenting consultation program are gathered and captured in central repository. Use of Praxis database for large operations projects.
Corporate Social Responsibility (CSR)
Manages the effectiveness with which the company meets its obligations, and achieves its objectives, with respect to being a responsible and good corporate citizen.</td></tr>
</table>

	• Responsible for public reporting and disclosure on the company's non-financial performance according to generally accepted guidelines for corporate reporting on social, environmental and governance issues. • Support for the CSR Committee of the EGD Board in the execution of its mandate to provide oversight and direction at the governance level on the company's performance on non-financial issues such as human rights, public awareness and consultation, issues management, environmental stewardship, external communications, government relations, stakeholder relations, Aboriginal relations, and community investment. • Integration of EGD's social and environmental performance priorities into cross-functional management systems with an emphasis on data management and control, stakeholder and community relations, employee engagement, procurement, risk management, investor relations, business development and project execution. • Leadership of enterprise-wide environmental initiatives on GHG reduction, energy conservation and environmental footprint reduction. • Strategic engagement with key external organizations regarding EGD's CSR and sustainability policies, practices and performance.
Service Recipient:	Mr. Jamie Milner, Vice-President Market Development and Customer Care, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
People and Partners	$65,443
Public, Government and Aboriginal Affairs	$202,876
Total	$268,319

Expected Deliverables

- Ensure that EGD's interests are represented to Federal Government Officials and staff
- Production and delivery of the CSR Report for EGD

Quality and Quantity of Service

- # of Government contacts relevant to EGD
- Positive relationships with key government entities
- Documented strategies
- Comprehensive policies meeting EGD's needs
- Investors and customers view EGD as a corporate environmental leader
- EGD is well recognized by reporting agencies as having a "best in class" reporting classification
- Plan clearly documents EGD's GHG emission levels, sources of emissions, emission reduction objectives and timelines
- Coordinate the overall development of CSR programs and initiatives on behalf of EGD including the establishment, implementation and measurement of objectives and targets for corporate social responsibility performance
- Liaising with customers and special interest groups with respect to EGD's position on issues and initiatives affecting EGD customer communities (e.g., corporate social responsibility)

Authorized Signature

Dec 15 /14

Mr. Jamie Milner
Vice-President Market Development
and Customer Care
Enbridge Gas Distribution

Date

35. Depreciation – Enterprise Systems

Service Description	
General Expense Definition:	Depreciation – Enterprise Systems contains the depreciation for IT systems that are used enterprise wide, including the EFS system.
Service Recipient:	Mr. Bill Ramos, Vice President Finance & Regulatory, Enbridge Gas Distribution
Cost of Service	
	$3,392,008
Authorized Signature	
	William M Ramos Mr. Bill Ramos Vice-President Finance & Regulatory Enbridge Gas Distribution Dec 15, 2014 Date

SEC INTERROGATORY #2

INTERROGATORY

Ref: [B/4/2, p. 1]

Line 20 of this Table shows a decline in the actual charges by Enbridge Inc. to the Applicant (CAM) from $44,977 Board-approved to $40,294 Actual, a decline of $4,683. Line 24 of this Table shows the adjustment to the CAM amount to get to the amount chargeable in rates (RCAM) declined from ($9,695) Board-approved, to ($6,677), a decline of $3,018, with the result that of the $4.7 million in savings from lower EI charges, only $1.7 million is being reflected in the ESM calculations. Please provide a detailed breakdown of the changes in the charges from EI, both CAM and RCAM, that have produced this result, and justify the lower savings to ratepayers.

RESPONSE

Enbridge Gas Distribution Inc. (“Enbridge” or the “Company”) has been receiving shared services from Enbridge Inc. (“EI”) for years.

CAM refers to the allocation of costs from EI to Enbridge for corporate shared services acquired by the Company. CAM sets the amount that Enbridge actually pays to EI for these shared services. The cost allocation methodology (“CAM”) is governed by an inter-corporate services agreement between the two parties, and the Affiliate Relationships Code for Gas Utilities (the “ARC”).

As part of the 2006 Rate Case, the Company brought forward a separate corporate cost allocation methodology called RCAM. The RCAM methodology is used to calculate the amount, in the context of Ontario regulation, that Enbridge can recover in rates for the corporate shared services acquired by the Company from EI during a given fiscal period. The RCAM methodology was developed with the objective of meeting the regulatory requirements of the Ontario Energy Board (“Board”) (as set out in the ARC Board decisions). This RCAM methodology was approved by the Board in EB-2006-0034 and has been applied to calculate the RCAM amounts throughout the incentive rate regulation period starting in 2008.

RCAM and CAM are different methodologies. CAM is still used by EI to transfer costs to all its affiliates, including Enbridge, for internal management and performance measurement purposes. CAM sets the amount that Enbridge pays to EI for the shared services. The RCAM is a service-based cost allocation methodology. It sets the amount that Enbridge can recover in rates for the shared services. Historically, the RCAM amount has been less than the CAM amount, meaning that Enbridge is recovering less in rates than it is paying for the shared corporate services from EI.

The referenced table in the prefiled evidence (Exhibit B, Tab 4, Schedule 2), sets out the amount paid by Enbridge under CAM in 2014 (line 20). That is not the amount that Enbridge recovered in rates in 2014. The approved RCAM amount recovered in rates for 2014 was $35.3 million (see EB-2012-0459 Decision, at pages 41 to 43). As set out in the materials circulated at the RCAM Consultative (see Attachment to Exhibit I.B.EGDI.SEC.1), the actual RCAM cost for 2014 was $33.6 million. The difference between those amounts ($1.7 million) contributes to the ESM amount being presented in this application.

Since the methodologies used for CAM and RCAM to calculate the allocated costs of the shared services are different, and since the amounts paid under CAM are not a component of Enbridge Gas Distribution's revenue requirement or rates, the changes in CAM versus the changes in RCAM are not a useful comparison. The fact that CAM amounts went down more than RCAM amounts for 2014 is not relevant to ESM calculations. Likewise, had the CAM amounts changed less than the RCAM amounts, there would have been no impact on the ESM calculations.

For an explanation of changes in CAM amounts for 2014 please refer to Energy Probe Interrogatory #8(c) (I.B.EGDI.EP.8(c)). The changes in RCAM amounts for 2014, which are seen in the materials circulated at the RCAM Consultative (see Attachment to Exhibit I.B.EGDI.SEC.1) arise from the same items, however, the financial impact of the changes is different under CAM and RCAM because of the difference in methodology as described above.

Witnesses: A. Patel
L. Stickles

SEC INTERROGATORY #3

INTERROGATORY

Ref: [B/4/2, and D/2/1]

For each reorganization or restructuring of operations and/or functions that affected the 2014 RCAM amounts (including but not limited to all changes of management structure, employment relationships, and ownership of assets), please provide:

a. A full description of the reorganization or restructuring.

b. The internal business case used to justify the reorganization or restructuring, including all cost benefit analyses.

c. A full breakdown of all costs, either part of RCAM or otherwise, for each of the affected operations and/or functions, including the amounts for each of 2013 and 2014, and where those amounts can be found in the OM&A or other costs of the Applicant in each of those years. By way of example, if a particular IT function was partly in the EGD IT department and partly in the Finance department in 2013, and is now a shared service provided by EI in 2014, please provide the amount that was in the IT department in 2013, what that amount was for, and what the amount for that part of the function was in the RCAM breakdown (including reference to the particular line in the tables) in 2014, plus the amount that was in the Finance department in 2013, what that amount was for, and what the amount for that part of the function was in the RCAM breakdown.

d. A full description of the total costs, and the detailed allocation tables, for each of those amounts that is included in the RCAM in either 2013 and 2014, so that it is possible to determine from the response the net incremental costs or savings associated with the change and how they were derived.

e. Where the cost of any operation or function borne by the Applicant's ratepayers increases as a result of a reorganization or restructuring, details of the increased benefits to the Applicant's ratepayers that are driving the increase in cost.

f. The number of employees related to each operation or function that, as a result of the reorganization and restructuring, will change employer or reporting relationships, and for all of those employees the number that will move from the Applicant's offices to another location at Enbridge Inc. For example, if a particular human resources function carried out by 15 employees has been restructured, so that 13 of the employees remain in Toronto doing the same functions, but become employees of EI, while two employees are made redundant and their activities are picked up by Calgary-based managers, please so describe.

g. All changes in ownership or location of assets, and the changes in costs borne by the Applicant's ratepayers as a result of each such change.

h. A table and/or narrative tracking the reorganizations and restructurings referenced to the Annual Productivity Report, showing in each case where the results of the reorganizations and restructurings are discussed in the Annual Productivity Report.

i. For each reorganization or restructuring, the actual savings generated by the initiative in 2014, and the forecast savings in each of 2015 through 2019, and in each case where those savings will show in the OM&A, RCAM, or other cost breakdowns.

RESPONSE

There were three reorganizations or restructurings of operations in 2014 that related to service areas subject to RCAM.

One of these, which related to the transfer of payroll services from EGD to EI, did not affect RCAM amounts. The reorganization for Payroll Management occurred in 2014, however, due to the methodology of RCAM, there are no charges to EGD in 2014 for this service as a result of the time study estimates used. As there are no changes in RCAM charges for 2014 related to this change, it is not addressed below in response to the specific questions asked.

The second restructuring relates to the reorganization of Brand Strategy & Community Investment Relations, and Government Relations & CSR. This change was internal to EI. There was an increase of $50,988 in RCAM costs for EGD for these services, as compared to the RCAM costs for similar services in 2013 before the reorganization.

The third restructuring relates to Information Technology ("IT"). This process was only partly implemented in 2014. The full implementation will take place in 2015, which is when the cost impact is expected. For 2014, the change in overall IT-related RCAM costs was a reduction of $271,016 for EGD. However, some of that change would not be related to the reorganization and would instead have related to changes in the ongoing IT costs for services that continued to be provided.

Witnesses: A. Patel
L. Stickles

The chart that is included as an Attachment to this response (Attachment I.B.EGDI.SEC.3) shows the RCAM cost changes in 2014 for the two areas noted above, in the shaded portions of the chart.

a) The reorganization of Brand Strategy & Community Investment Relations, and Government Relations & CSR was internal to EI. Please refer to the Attachment to SEC Interrogatory #1 (I.B.EGDI.SEC.1) pages 52 to 55 for the new service schedules which include a description of what services are being provided. These services are broadly similar to what was previously provided under the headings "Industry Relations & Corporate Social Responsibility ("CSR")" and "Government Relations".

   The reorganizations for IT involve moving to shared IT services with EI. The reorganizations for IT are occurring in two parts. Part 1 is to put the structure in place at EI, which are the new services that are showing in the 2014 RCAM schedules (Attachment I.B.EGDI.SEC.1 pages 32 to 51). Part 2 is to move costs from EGD to EI. This part is not occurring until 2015. In 2015 there will be a reduction of costs at EGD, and an increase in costs via RCAM as these IT services are centralized and charged to EGD through corporate cost allocations.

b) EGD does not have a business case related to EI's reorganization of its Brand Strategy & Community Investment Relations, and Government Relations & CSR.

   For the restructurings related to IT services, EGD will be filing a business case within an upcoming application seeking an Affiliate Relationship Code exemption.

c) The costs associated with the Brand Strategy & Community Investment Relations, and Government Relations & CSR services and the IT services being provided are set out in the RCAM service schedules found in the Attachment to SEC Interrogatory #1(I.B.EGDI.SEC.1). It is not expected that the restructurings resulted in changes to EGD's own costs in 2014.

d) Please refer to the Attachment Exhibit I.B.EGDI.SEC.3.

e) There is minimal financial impact in 2014 from the re-organizations/ restructurings that are described in part a).

f) There is minimal financial impact in 2014 from the re-organizations/ restructurings that are described in part a).

Witnesses: A. Patel
L. Stickles

g) There is no change in ownership or location of assets in 2014 as a result of the re-organizations/ restructurings that are described in part a).

h) The re-organizations/ restructurings that are described in part a) did not result in productivity savings that are discussed in the Annual Productivity Report.

i) EGD will be filing a business case detailing the reorganization of IT services within an upcoming application seeking an Affiliate Relationship Code exemption. It is expected that this will include information about forecast savings and other benefits.

Witnesses: A. Patel
L. Stickles

24. Payroll Management

Service Description	
Service Definition:	The Payroll Management service is responsible for providing the enterprise-wide administration and processes related to payroll management, payroll tax processing and time reporting.
Services Identified by Department	**HR Employee Services** The Payroll Management service is responsible for providing the enterprise-wide administration and processes related to payroll management, payroll tax processing and time reporting. The HR Employee Services Department supports this service by assuming responsibility for the management of all aspects of payroll services. Examples of activities related to the provision of the service: • Define and Set Up Payroll foundational tables (taxes, garnishments, compensation) • Enter and manage employee time worked into payroll system • Maintain and administer employee earnings information • Maintain and administer applicable deductions • Monitor changes in status of employees (tax, union group, etc) • Process and distribute payments to internal and external groups • Process and distribute manual cheques, direct deposits, online advices • Reconcile and distribute payroll information relating to GL, Vendors, A/P • Provide pay period, monthly, quarterly and annual reporting and reconciliations • Provide support to internal/external audit • Process period end adjustments • Respond to employee payroll inquiries • Calculate and pay applicable payroll taxes • Produce and distribute employee annual tax statements • File regulatory payroll tax forms • Define and Set Up Time and Labour foundational tables (create groups, schedules) • Create and collect timesheet as per the defined work schedule • Upload all time from timesheets to be paid through payroll • Collect and record employee time worked • Analyze and report paid and unpaid leave • Respond to employee, People Leader, HR and other stakeholder inquiries via telephone, email and internet and expeditiously resolve, as the case may be.
Service Recipient:	Mr. Dave Charleson, Sr Director Human Resources & Facilities, Enbridge Gas Distribution

Cost of Service

Department	Service Charge
HR Employee Services	$0
Total	$0

Expected Deliverables

- Accurate processing of employee payments on time
- Timely and accurate issuance of employee tax statements
- Timely and accurate submission of all legislative remittances and filing requirements

Appendix "B" to the Regulatory Cost Allocation Methodology Confirmation Notice between Enbridge Inc. and Enbridge Gas Distribution Inc., for the year 2014

	• Respond to all internal and external inquiries within three business days
Quantity and Quality of Service	
	• On demand access to support during established business hours • Positive employee experience • Reduced payroll costs • Comprehensive services at a competitive price
Authorized Signature	
	Mr. Dave Charleson Sr Director Human Resources & Facilities Enbridge Gas Distribution Dec 15/14 Date

EGD Service Recipient ‘s CCA Business Case
2014 Payroll Management
Service Recipient: Dave Charleson

PART I: Service Requirements Justification

For those services that you have identified as required for 2014, please provide the following information:

☐ Please explain in sufficient detail why each of the services is **specifically required** for the operation of EGD

Note: this is a new service in Q2-2014.

Payroll Management is critical to ensuring that all employees are paid for the work that they perform for EGD. The activity is also required to ensure that all necessary statutory and other deductions (e.g. taxes, EI, CPP, benefit contributions) are appropriately deducted from the employees pay and remitted to the appropriate body. Payroll Management also ensures that all legislatively required reporting and advices are prepared and provided in the required time periods.

☐ Please provide **scope and service level** for the required services below:

Itemize Services/Deliverables (include examples)	**Expected Service Level (Quantity and Quality Indicators)**
General: Accurate processing of employee payments on time	 Payroll deposits for all employees to the financial institution accounts designated by employees will be made according to the pay schedule. Payments will be accurate, based on information provided by EGD, with all required statutory deductions and other withholdings being deducted.
Timely and accurate issuance of employee tax statements.	All tax statements that are required by legislation will be issued to employees and former employees as necessary, in accordance with legislative requirements. These statements will be accurate and free of errors.
Timely and accurate submission of all legislative remittances and filing requirements Examples: Payroll taxes, EI and CPP	All government remittances and other legislative filing requirements related to employee deductions, employer contributions and any other legislated or legal obligations are accurately completed in accordance with the schedules dictated by legislation.

deductions, Records of Employment Respond to all internal and external inquiries within three business days	 All payroll related enquiries, whether from employees or other internal clients or external bodies, are responded to within three business days.

Identify whether EI is currently the **sole provider** of those services **or a supplemental** provider

EI is a sole provider.

PART II: Excluded Services

For those services that you have identified as **not** required for 2014, please identify the rationale for exclusion by marking one or more of the applicable boxes below with an "X"

Itemize Excluded Services	**Ref ***	**Exclusion Criteria**			
		Standardization	**Minding the Investment**	**Additional Management Layer**	**Other (please specify)**
None					

* service schedule dept #/item#

PART III: COST ESTIMATES UNDER VARIOUS SERVICE DELIVERY MODELS

Instructions:

1. ***For those services that can be acquired externally through independent third-party service providers (i.e., a reasonably competitive market exists for the required services), please ensure the pricing section for the external alternative is completed.*** *If a reasonably competitive market does not exist, please explain why not.*

The services can be acquired externally through an independent third-party service provider. However, this would require a number of resources to remain within EGD to coordinate the payroll activities with the service provider.

An independent third party assessment of acquiring these services through an independent third party was required to obtain a reasonable market comparator, as representative third-party costs are difficult to obtain in the absence of a legitimate bidding process.

2. ***For all services, as an alternative to the services currently acquired from EI via the shared services model, it should be assumed that the required services can be delivered in house. It is mandatory that the pricing section for the in-house alternative be completed.***

3. ***The RCAM co-ordinator will complete the EI service delivery cost section for all services.***

If the equivalent services can be acquired externally, what would the annual cost be at market rate?

	# of Consultants Required		# Hours per Consultant		Hourly Market Rate		Estimated $	
	2013	2014	2013	2014	2013	2014*	2013	2014
Managing Partners	N/A	0	0	0	0	0	N/A	0
Senior Consultants	N/A	0	0	0	0	0	N/A	0
Consultants	N/A	0	0	0	0	0	N/A	0
Support Staff	N/A	0	0	0	0	0	N/A	0
Sub-total (Fees)							**N/A**	**0**
Other disbursements, please detail type of expense and costing assumptions:								
External consulting: Payroll							N/A	184,311
Internal support staff:								
1 Mid Mgr (@ $142,007+35% STIP/LTIP + 31% Benefits + 25.1% Support Costs)							N/A	271,356
2.4 Analysts (@ 64,386 +5% STIP + 31% Benefits + 55.3% Support Costs)							N/A	295,653
Training & Development							N/A	2,100
Travel & Entertainment							N/A	6,400
Sub-total (disbursements)								
Total – Mean							**N/A**	**$759,820**
Total – Lower Range (80% of Mean)							**N/A**	**$607,856**
Total – Upper Range (120% of Mean)							**N/A**	**$911,784**
***** *2013 values are inflated by the forecast 2014 Ontario CPI of 2.2%*								

If the equivalent services are to be performed by EGD personnel, how much would it cost on a fully–loaded basis?

	No. of FTEs Required		Average Job Rate (Salary plus incentive compensation)		Benefits Multiplier (% of Salary)		Occupancy Multiplier (% of Salary)		Estimated $	
	2013	2014	20132	2014	2013	2014	2013	2014	2013	2014
Executive Management			$576,958	$544,726	32%	42%	1.7%	13.4%		
Senior Management			$305,649	$307,091	32%	42%	2.3%	18.6%		
Middle Management	N/A	0.5	$185,326	$191,710	30%	31%	2.4%	25.1%	N/A	135,678
Professional/ Technical	N/A	1	$85,721	$98,330	30%	31%	1.9%	40.7%	N/A	161,061
Union	N/A	4	$68,784	$67,605	27%	31%	1.2%	55.3%	N/A	492,755
Other expenses, please detail type of expense and costing assumptions:										
Training									N/A	3,500
Travel & Entertainment									N/A	10,400
As of 2010 the no. of FTEs required has been rounded to reflect the following rules: Below 0.25, the value stays the same Above or equal to 0.25 but below 0.5, the value rounds to 0.5 FTE Above 0.5, the value rounds to 1 FTE										
Qualifying note: the above rounding rules represent a very conservative costing approach. It is not practical for EGD to hire fractions of FTEs, as EGD would be obliged to hire whole FTEs.										
Total - Mean									**N/A**	**$803,394**
Total – Lower Range (80% of Mean)									**N/A**	**$642,716**
Total – Upper Range (120% of Mean)									**N/A**	**$964,073**

Notes:

- Annual incentive compensation including Stock Based Compensation (where applicable) is incorporated into the average job rates.
- Benefits Multiplier incorporates employee benefits, including short term disability and scheduled day-off benefits. It excludes recruitment/severance and training & development costs
- Occupancy Multiplier incorporates office space, building interior/exterior maintenance, furniture and IT O&M costs. Beginning in 2010, O&M and depreciation costs inclusive of CIS but exclusive of Envision were used.
- For other expenses, 2013 costs are Inflated by the forecast 2013 Ontario CPI of 2.2%

If the services are to be provided by EI, please provide cost breakdown

Type of Charge		**Allocator** (ex: time, volumetric, capital employed or headcount)	**Unit** (ex: % time, m^3, capital $, or # of headcount)	**Total $**	
				2013 (EI's 2013 budget)	**2014** (EI's 2014 budget)
Direct	Primary Service	Time	%	N/A	0
	Support Service	Time	%	N/A	0
	Total			N/A	0
Indirect	Primary Service	Employees	%	N/A	0
	Support Service	Employees	%	N/A	0
	Total			N/A	0
Total Primary Service*				N/A	0
Total Support Service**				N/A	0
Total				**N/A**	**$0**

Comments:
(Discussion of reasonableness of EI cost)

The economies of scale derived throughout this service provide a significant cost saving for EGD. In addition, senior technical expertise is provided on an "as needed" basis, at a lower cost than would be incurred by the use of an external third party.

* Total Primary Service Fully Loaded Dept. Costs includes the following cost components-Labour Salary, Benefits, Stock Based Comp; Training Expenses; Travel Expenses; Professional Fees; Rent +Taxes; Furniture, Computers, Equipment and Office Materials

** Total Support Service Burden includes the following cost components-Financial Projects Support (Financial Associate Program; Environmental, Health & Safety; Helpdesk, Network, Infrastructure and Hardware Support; Information System Support; Invoice Processing and Payment; Payroll and Benefits Processing; Corporate General Accounting; Corporate Office Administration; IT Project Management Support; IT Software Support & Maintenance

Note: consistent with the design of the RCAM methodology, there was no time recorded against 2014 RCAM and hence no charge in 2014 related to this service. Time and costs will be reflected starting 2015.

PART IV: Cost Benefit Analysis

	E.I	***External***	***EGD***
Service Cost (per Part III	**$0**	**$607,856 - $911,784**	**$642,716 - $964,073**
Benefits to Ratepayers (tangibles/intangibles) ***Examples:*** Economies of Scale Continuity of Service: Anticipate emerging needs, trends or issues, unlimited flat-rate consultation services Adaptability: Business tools commonality Expertise/Knowledge: familiarity with EGD processes, vision, values and objectives	Economies of scale are achieved. Costs of processing payroll and managing and addressing payroll changes are shared among affiliates rather than being incurred on a standalone basis by EGD.	Service would be comparable to that received from EI but would not have the Enbridge specific knowledge.	Service was being done internally and that could have continued. However this required additional management attention and was at a higher cost than the option of outsourcing to EI.

SUMMARY - Service provider selected and justification:

Provision of service by EI on an allocated basis as there are no allocated costs during the transition year.

PART V: Year-over-year Cost Variance Explanation

New service, so no year over year comparison available.

Prepared by ________________________ **Date**____________________

Approved by________________________ **Date**____________________

Attachment 2 to the 2014 RCAM Report
2014 vs. 2013 EGD RCAM Allocations Variance Analysis
Services re-shuffled to show 2014 cost impact

Services / Direct Charges	Allocation to EGD 2014	Allocation to EGD 2013	$ Variance	% Variance	Explanation
Audit & Accounting Advice	$ 134,343	$ 158,418	$ (24,075)	-15.2%	
Board of Directors Support	$ 707,990	$ 848,267	$ (140,277)	-16.5%	
Business & Economic Financial Analysis	$ -	$ -	$ -	0%	
Business Development	$ 303,345	$ 751,127	$ (447,782)	-59.6%	Lower support cost due to support services restructuring and reduced activities in Corporate Law
Capital Market Financing & Access	$ 745,805	$ 1,029,508	$ (283,703)	-27.6%	Lower support cost due to support services restructuring and lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
Cash Management & Banking	$ 249,517	$ 997,480	$ (747,963)	-75.0%	Reduction in activities performed by Treasury from the higher level in 2013 as noted in the 2013 explanation
Corporate Compliance	$ 201,541	$ 290,362	$ (88,821)	-30.6%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
Emerging Energy Technology Research	$ -	$ -	$ -	0%	
Employee Development	$ 1,140,897	$ 1,318,597	$ (177,700)	-13.5%	
External Audit Coordination	$ 103,364	$ 207,076	$ (103,712)	-50.1%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
Gas Supply, Storage, and Transportation Strategy	$ -	$ -	$ -	0%	
Human Resource Advice	$ 312,301	$ 171,633	$ 140,668	82.0%	Increase in HR strategic development costs. This service has been provided in prior years however the costs were never allocated. The increase is due to the costs now being allocated.
Insurance Claims Support, Strategy and Management	$ 199,281	$ 325,570	$ (126,289)	-38.8%	Lower activities following the renewal/restructuring of the insurance policies, lower support cost due to support services restructuring and lower cost base due to redistribution of SBC/STIP across a wider base
Investor Services	$ 1,014,165	$ 1,099,448	$ (85,283)	-7.8%	
Legal Advice	$ 487,544	$ 465,382	$ 22,162	4.8%	
Planning, Management & Execution of Internal Audits	$ 359,369	$ 243,067	$ 116,301	47.8%	Restructuring of Internal Controls function from a support to a primary service
Rate Regulated Entity Support	$ 209,479	$ 225,727	$ (16,248)	-7.2%	
Records and Information Management	$ 1,054,087	$ 888,504	$ 165,583	18.6%	Significant increase in the number of users of Livelink (Enterprise Content Server) as a result of the email management rollout, partially offset by the restructuring of ECM to IT
Risk Assessment and Management	$ 654,230	$ 865,435	$ (211,205)	-24.4%	Reduced enterprise risk activities and lower support cost due to support services restructuring
Strategic Planning	$ 223,115	$ 253,073	$ (29,958)	-11.8%	
Supply Chain Management	$ 53,482	$ 46,900	$ 6,582	14.0%	
Tax Reporting & Planning	$ 70,384	$ 131,679	$ (61,295)	-46.5%	Reduced time spent on EGD
Total Compensation and Benefits	$ 1,908,125	$ 2,399,292	$ (491,167)	-20.5%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure and lower support cost due to support services restructuring
Employee and Labour Relations	$ 481,772	$ 588,542	$ (106,770)	-18.1%	Lower cost base due to redistribution of SBC/STIP across a wider base to reflect the current compensation structure
Consolidation and Planning System Technical Support (Khalix)	$ -	$ 275,164	$ (275,164)	N/A	Service removed due to reorganization of primary services within IT
Enterprise IT Program Management	$ -	$ 661,348	$ (661,348)	N/A	Service removed due to reorganization of primary services within IT
Enterprise IT Strategy Planning & Management	$ -	$ 236,125	$ (236,125)	N/A	Service removed due to reorganization of primary services within IT
Expense System Management & Technical Support (Oracle iExpense)	$ -	$ 240,347	$ (240,347)	N/A	Service removed due to reorganization of primary services within IT
Financial and Project Accounting System Technical Support (Oracle)	$ -	$ 517,170	$ (517,170)	N/A	Service removed due to reorganization of primary services within IT
HRIS Program Management and Development	$ -	$ 3,487,053	$ (3,487,053)	N/A	Service removed due to reorganization of primary services between HR and IT
Portal Suite Operations & Technical Support	$ -	$ 301,334	$ (301,334)	N/A	Service removed due to reorganization of primary services within IT
Enterprise System Program and Project Management	$ 1,611,719	$ -	$ 1,611,719	N/A	New Service due to reorganization of IT and IT related services
Enterprise Infrastructure Program and Project Management	$ 86,548	$ -	$ 86,548	N/A	New Service due to reorganization of IT and IT related services
Enterprise System Management and Technical Support	$ 4,902,304	$ -	$ 4,902,304	N/A	New Service due to reorganization of IT and IT related services
Enterprise Infrastructure Management and Technical Support	$ -	$ -	$ -	N/A	New Service due to reorganization of IT and IT related services
IT Planning and Governance	$ 1,718,004	$ -	$ 1,718,004	N/A	New Service due to reorganization of IT and IT related services
Direct EFS Charge (Credit)	$ (5,000,103)	$ (2,129,052)	$ (2,871,051)	134.9%	As EFS increases the enterprise costs that are budgeted at EGD, there is a corresponding higher credit to EGD to reflect the usage of service
Service Impact in 2014	**$ 3,318,472**	**$ 3,589,488**	**$ (271,016)**	**-7.6%**	
Industry Relations & Corporate Social Responsibility (CSR)	$ -	$ 415,918	$ (415,918)	N/A	Service removed due to reorganization of primary services within PG&A
Government Relations	$ -	$ 48,971	$ (48,971)	N/A	Service removed due to reorganization of primary services within PG&A
Brand Strategy & Community Investment Relations	$ 247,559	$ -	$ 247,559	N/A	New Service due to reorganization PG&A services
Government Relations & CSR	$ 268,319	$ -	$ 268,319	N/A	New Service due to reorganization PG&A services
Service Impact in 2014	**$ 515,878**	**$ 464,889**	**$ 50,988**	**11.0%**	
Payroll Services	$ -	$ -	$ -	N/A	New Service due to centralization of service at Corporate EI
Safety and Process Safety	$ -	$ -	$ -	N/A	New Service - new business requirement
Total Charges	$ 14,448,484	$ 17,359,464	$ (2,910,980)	-16.8%	
Directors Fees & Expenses	$ 1,223,750	$ 1,089,370	$ 134,380	12.3%	
Depreciation - Risk Management System	$ 25,132	$ 133,581	$ (108,449)	-81.2%	
Depreciation - Enterprise Systems	$ 3,392,008	$ -	$ 3,392,008	N/A	New assets requirements to implement the FRP roadmap and as a result of the centralization of the IT infrastructure systems at Corporate
Insurance Premiums	$ 4,830,857	$ 5,652,239	$ (821,382)	-14.5%	Continues to see cost savings in 2014 post restructuring of insurance policies
BU Stock Based Compensation Charge	$ 9,225,003	$ 10,657,647	$ (1,432,645)	-13.4%	Reduction is a function of the number of participants and stock prices
Total Charges	$ 18,696,750	$ 17,532,837	$ 1,163,912	6.6%	
Return on Invested Capital	$ 471,684	$ 353,189	$ 118,495	33.5%	
Total EGD Allocation	**$ 33,616,917**	**$ 35,245,490**	**$ (1,628,573)**	**-4.6%**	

VECC INTERROGATORY #4

INTERROGATORY

Reference: B/T4/S2/pg.2 (PDF pg. 95) & D/T2/S1/pg.12 (PDF pg. 177)

a) Please explain how (or if) the Short Term Incentive (STIP) payments (or other compensation incentives) were affected by EGD's failure to achieve many of the embedded OM&A productivity savings and nearly all of the capital savings (Table 5).

RESPONSE

As set out in response to FRPO Interrogatory #6 (Exhibit I.B.EGDI.FRPO.6), Enbridge Gas Distribution's (Enbridge's) 2014 Short Term Incentive Program ("STIP") was based on the following three factors:

1) Enbridge companywide performance;
2) Enbridge Gas Distribution corporate performance:
3) Individual employee performance.

To the extent that there were specific productivity initiatives or savings targets embedded into individual employee performance targets, or to the extent that these affect the overall financial performance of the company, they would affect the STIP calculation. This impact would be different for each employee.

Witnesses: A. Patel
L. Stickles

BOARD STAFF INTERROGATORY #1

INTERROGATORY

2014 Unabsorbed Demand Charges Deferral Account and 2014 Design Day Criteria Transportation Deferral Account

Ref: ExC1/T1/S2/ page 3 of 6 / para 8

At para 8 the evidence speaks to the establishment in 2014 of two deferral accounts: the 2014 UDCDA and the 2014 DDCTDA.

> "In early November 2013, the Company reached a Settlement Agreement with parties to include in the 2014 DDCTDA the cost consequences of unutilized transportation costs associated with the change in the Peak Gas Design Day Criteria approved by the Board in EB-2011-0354, which was to be phased in equally over the 2013 and 2014 fiscal years and to the establishment of the 2014 UDCDA to capture the cost consequences of unutilized capacity in excess of the amounts recorded in the 2014 DDCTDA."

a) Please explain how Enbridge differentiates between the UDC that was attributable to the Peak Gas Design Day criteria, and the UDC that was "to capture the cost consequences of unutilized capacity in excess of the amounts recorded in the 2014 DDCTDA"?

b) Please describe what actions the Company undertook in 2014 to lessen the impact of UDC costs as it executed its gas supply plan. Please quantify the UDC costs that were mitigated.

RESPONSE

a) In EB-2011-0354, the Company applied for an increase in the Peak Gas Day Design Criteria. The Board-approved Settlement Agreement set out the agreement by parties that the resultant change to peak day design heating degree days would be increased incrementally over the 2013 and 2014 years. The agreement also noted that meeting the resultant increase in design peak day demand would necessitate the Company acquiring incremental transportation and that the cost consequences of unutilized transportation would be recorded in the 2013 and the 2014 Design Day Criteria Transportation Deferral Account (DDCTDA).

Witnesses: J. Leblanc
D. Small

As part of its evidence in EB-2012-0459 (Exhibit D1, Tab 2, Schedule 1, page 14 of 20), the Company reiterated that it would require an additional 85,000 GJ/day of capacity in 2014 to accommodate the change in Peak Gas Day Design Criteria. The Company also indicated the UDC associated with this capacity forecasted to be recorded in the 2014 DDCTDA was $41.5 million (26.3 PJ).

The Company went on to explain on page 15 of its evidence in EB-2012-0459 that because of the changes in TCPL tolling for STFT service, it was more economical to acquire one year FT transportation capacity for 2014. Doing so, however, would result in additional unutilized FT capacity which would have additional UDC cost consequences during 2014. As a part of the Board-approved Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1), parties agreed that the additional unutilized costs associated with this FT capacity would be captured in a separate account, which led to the establishment of the 2014 UDCDA. The Company forecasted a projected balance in the 2014 UDCDA of $62.8 million (39.7 PJ).

At page 20 of its evidence in EB-2012-0459, the Company also provided a forecast of the monthly unutilized capacity broken down between the 2014 DDCTDA and the 2014 UDCDA. A copy of the report outlining this unutilized capacity is attached as Attachment 1.

For purposes of recording actual unutilized costs between the two deferral accounts, the Company adopted the principle that on any day when there was unutilized capacity, the costs associated with the first 85,000 GJ would be captured in the 2014 DDCTDA and any unutilized costs associated with amounts greater than 85,000 GJ/day would be captured in the 2014 UDCDA. Any revenues received by the Company from releasing the unutilized capacity to third parties was allocated between the two deferral accounts on a volumetric basis. A report detailing the actual breakdown of the unutilized cost consequences and the associated revenues received from the release of that capacity between the 2014 DDCTDA and the 2014 UDCDA was filed with Board on a monthly basis throughout 2014. A copy of the December 2014 report is attached for reference as Attachment 2.

For example, in the month of August 2014 the Company had 6.7 PJ of unutilized capacity of which 2.6 PJ was deemed to be related to the change in Design Day Criteria (85,000 GJ x 31 days = 2,635,000 GJ) and the remaining 4.1 PJ was deemed to be related to incremental transportation requirement. In August 2014 the Company received $1.5 million from third parties pertaining to the capacity that was released to them either through a month-long transaction or on the day. Therefore, $0.6 million of the revenue received was allocated to the DDCTDA (2.6 PJ/6.7 PJ X $1.5 million).

b) The purpose of the 2014 DDCTDA and the 2014 UDCDA was to capture the unutilized cost associated with the Company's inability to utilize 100% of its contracted long haul capacity to either meet customer demand and/or fill storage on a budgeted basis.

During the period of January 2014 to March 2014, the colder than budget weather resulted in the Company fully utilizing its long haul FT capacity. This avoided the costs associated with the original forecasted 26.9 PJ of unutilized capacity as shown in the forecasted UDC exhibit filed as Attachment 2

During the month of March 2014, the Gas Supply group began reviewing its supply plan for the month of April and made the decision that it would maximize its utilization of contracted long haul FT capacity in the month. This decision was made to protect against colder than budget weather in the first part of April and to mitigate operational concerns with respect to the amount of gas that the group anticipated it needed to inject into storage over the summer. Similar decisions were made in April and in May with respect to injection requirements for the months of May and June. As a consequence the group again decided to fully utilize its contracted long haul capacity and therefore avoided an additional 15.0 PJ of originally forecasted unutilized capacity.

During the month of June 2014, representatives from the Gas Supply group met again to evaluate current storage balances and to discuss expectations for daily injection requirements throughout the month of July. The Gas Supply group decided to release approximately 50,000 GJ per day as part of a monthly release and to release an additional 20,000 to 60,000 GJ per day on the day dependent upon actual daily injection quotas. In total, 3.1 PJ of capacity was released for approximately $0.9 million in revenue.

Similar discussions were held throughout July and August 2014 to determine the amount of capacity that could be released through a combination of monthly and daily releases throughout the months of August and September. During the month of August a total of 6.7 PJ was released for approximately $1.5 million in revenue and in the month September a total of 5.2 PJ was released for approximately $1.2 million in revenue.

In the month of September 2014, the Gas Supply group held similar discussions regarding the month of October. However, because of the potential for an increase in demand during the month of October the group chose to release a lower level of daily capacity for the entire month and then when necessary release a greater quantity on the day. In total, 5.1 PJ was released for revenues of approximately $1.7 million.

The table attached as Attachment 3 provides a breakdown of the volume released either on a monthly or daily basis throughout the July to October period and the revenues received from those releases.

Finally, in its 2015 rate application (EB-2014-0276), the Company indicated that going forward it was not necessary to maintain two deferral accounts to track the cost consequences of unutilized transportation capacity. The Company proposed a single account, the 2015 UDCDA, which was approved by the Board.

Witnesses: J. Leblanc
D. Small

Forecasted Monetary Impacts by Delivery Area														
$ millions														
UDCDA														
- CDA	44.0													
- EDA	18.8													
	62.8													
DDCTDA														
- CDA	36.2													
- EDA	5.3													
	41.5													
Forecasted Monthly Unutilized Capacity by Delivery Area														
PJs (millions of GJs)														
	January	February	March	April	May	June	July	August	September	October	November	December		
UDCDA														
- CDA	4.250	3.740	4.590	1.950	2.015	1.950	2.015	2.015	1.950	2.015	1.603	-		28.093
- EDA	2.125	1.870	4.077	0.450	0.465	0.450	0.465	0.465	0.450	0.465	0.330	-		11.612
	6.375	5.610	8.667	2.400	2.480	2.400	2.480	2.480	2.400	2.480	1.933	-		39.705
DDCTDA														
- CDA	1.863	1.639	2.012	2.235	2.310	2.235	2.310	2.310	2.235	2.310	1.639	-		23.095
- EDA	0.263	0.231	0.284	0.315	0.326	0.315	0.326	0.326	0.315	0.326	0.231	-		3.255
	2.125	1.870	2.295	2.550	2.635	2.550	2.635	2.635	2.550	2.635	1.870	-		26.350
Total														
- CDA	6.113	5.379	6.602	4.185	4.325	4.185	4.325	4.325	4.185	4.325	3.242	-		51.188
- EDA	2.388	2.101	4.361	0.765	0.791	0.765	0.791	0.791	0.765	0.791	0.561	-		14.867
	8.500	7.480	10.962	4.950	5.115	4.950	5.115	5.115	4.950	5.115	3.803	-		66.055
Forecasted Degree Days														
Central Region	682	591	504	302	130	29	0	5	56	240	391	587		3517
Niagara Region	659	592	490	305	**137**	23	0	3	43	215	365	554		3386
Eastern Region	821	701	592	338	152	38	7	21	109	285	463	716		4243
Forecasted Summer Discretionary Requirement														
PJs	18.301													

Witnesses: J. Denomy
D. Small

ENBRIDGE

500 Consumers Road
North York ON M2J 1P8
P.O. Box 650
Scarborough, ON
M1K 5E3

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance
Tel 416-495-5499 or 1-888-659-0685
Fax 416-495-6072
Email egdregulatoryproceedings@enbridge.com

December 31, 2014

VIA RESS and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, p. 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014. Please see the attached report for November, 2014.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2012-0459 Interested Parties

December 2014 Report

Demand	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual - Updated July	Actual August	Actual September	Actual October	Actual November	Estimate December	
PJ's	85.9	73.1	70.5	40.9	22.1	15.4	15.4	14.7	16.5	27.0	51.7	60.6	493.9

Forecasted Monetary Impacts by Delivery Area
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.6	4.5	2.9	3.2	-	-	11.2
- EDA	-	-	-	-	-	-	0.3	2.0	1.3	1.4	-	-	5.0
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.2)	(0.9)	(0.6)	(1.0)	-	-	(2.7)
Net Impact on Deferral Account	-	-	-	-	-	-	0.7	5.5	3.6	3.7	-	-	13.6
DDCTDA													
- CDA	-	-	-	-	-	-	3.5	3.6	3.5	3.0	-	-	13.6
- EDA	-	-	-	-	-	-	0.5	0.5	0.5	0.4	-	-	1.9
Revenue From Unutilized Capacity Released	-	-	-	-	-	-	(0.8)	(0.6)	(0.6)	(0.7)	-	-	(2.6)
Net Impact on Deferral Account	-	-	-	-	-	-	3.2	3.5	3.4	2.7	-	-	12.9

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA													
- CDA	-	-	-	-	-	-	0.4	2.8	1.9	2.1	-	-	7.2
- EDA	-	-	-	-	-	-	0.2	1.2	0.8	0.9	-	-	3.1
Unutilized Capacity Released	-	-	-	-	-	-	(0.6)	(4.1)	(2.7)	(3.0)	-	-	(10.2)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
DDCTDA													
- CDA	-	-	-	-	-	-	2.2	2.3	2.3	1.9	-	-	8.7
- EDA	-	-	-	-	-	-	0.3	0.3	0.3	0.3	-	-	1.2
Unutilized Capacity Released	-	-	-	-	-	-	(2.5)	(2.6)	(2.6)	(2.2)	-	-	(9.9)
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-
Total													
- CDA	-	-	-	-	-	-	2.6	5.2	4.1	4.0	-	-	15.9
- EDA	-	-	-	-	-	-	0.5	1.5	1.1	1.1	-	-	4.2
Unutilized Capacity Released	-						(3.1)	(6.7)	(5.2)	(5.1)	-		
Net Unutilized Capacity	-	-	-	-	-	-	-	-	-	-	-	-	20.1

Degree Days													
Central Region	813.0	724.1	669.3	352.3	127.4	12.6	4.9	9.3	70.0	230.7	474.2	550.0	4,037.8
Niagara Region	758.1	679.1	637.5	330.0	137.6	14.9	5.1	5.8	69.9	203.1	439.6	526.1	3,806.8
Eastern Region	895.2	775.3	751.1	381.2	124.0	14.9	10.4	22.0	115.3	260.9	507.7	725.7	4,583.7

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	15.0	16.2	21.8	9.0	-	-	-	-	-	-	5.1	13.5	80.6

Month end Storage Capacity												
% Fill	0.39	0.19	0.14	0.20	0.35	0.49	0.75	0.87	0.97	1.00	0.94	0.78

Month end Storage Capacity Taget												
% Fill	0.47	0.24	0.06	0.07	0.20	0.36	0.56	0.75	0.92	1.00	0.95	0.78

2014 Capacity Release

	Jul-14				Aug-14				Sep-14				Oct-14			
	Volume Released PJ's	Revenue Received $ (millions)	Average Unit Rate $/GJ	# of Transactions	Volume Released PJ's	Revenue Received $ (millions)	Average Unit Rate $/GJ	# of Transactions	Volume Released PJ's	Revenue Received $ (millions)	Average Unit Rate $/GJ	# of Transactions	Volume Released PJ's	Revenue Received $ (millions)	Average Unit Rate $/GJ	# of Transactions
Montly Releases	1.635	0.540	0.330	1	3.410	0.835	0.245	3	3.233	0.623	0.193	4	1.550	0.388	0.250	2
Daily Releases	1.420	0.397	0.279	51	3.296	0.685	0.208	103	1.981	0.548	0.277	84	3.570	1.297	0.363	98
Total Capacity Released	3.055	0.936	0.306		6.706	1.520	0.227		5.215	1.171	0.225		5.120	1.685	0.329	

BOARD STAFF INTERROGATORY #2

INTERROGATORY

2014 Unabsorbed Demand Charges Deferral Account and 2014 Design Day Criteria Transportation Deferral Account

Ref: ExC1/T1/S2/ page 5 of 6 / para 13

At para 13 the evidence speaks to the amounts in the 2014 UDCDA and the 2014 DDCTDA, and how revenue was generated.

"For the months of July to October the Company released capacity that it did not otherwise need through a combination of monthly and daily releases. As the attached report illustrates, the Company experienced 20.1 PJ's of unutilized capacity which it was 100% successful in releasing to third parties. The cost of this capacity was $31.7 million and the Company was able to generate $5.3 million in revenue. The result is that there is a net UDC cost of $26.4 million to be recovered from customers - $12.9 million in the 2014 DDCTDA and $13.6 million in the 2014 UDCDA."

a) Given that the revenue generated was $5.3 million while the costs of the unutilized capacity was $31.7 million, is it fair to conclude that the secondary market values such capacity at 5.3/31.7 = 16.7% or about 17 cents on the dollar? Would this be valid as a rule of thumb for mitigation of UDC costs?

b) Is there any available market data that would provide a benchmark of the fair value set by the secondary markets in gas transportation for the period in which Enbridge posted amounts in the deferral accounts?

RESPONSE

a) There is no rule of thumb that can be established for determining the value of transportation capacity released by the Company. Transportation capacity is traded in the secondary market. Consequently the value of transportation capacity is influenced by several factors including, but not limited to, market fundamentals such as supply and demand conditions and the time of day and time of year. The impact of these factors is more fully discussed in the response to part b) below.

Witnesses: J. Leblanc
D. Small

The Company does not dispute the calculation that would suggest a value of 17 cents on the dollar for the value of mitigation of UDC costs. However, this is merely a representation of the average market value over the period of July 2014 to October 2014 and would not necessarily be indicative of the value in a future period nor indicative of the value received for any individual transaction.

A review of the table provided as Attachment 3 in response to Board Staff Interrogatory 1(b) found at Exhibit I.C.EGDI.STAFF.1, indicates that the revenue received by the Company over the period of July 2014 to October 2014 ranged anywhere between $0.19 /GJ and $0.36/GJ. Based on the TCPL Empress to CDA toll in place at the time of $1.56/GJ, the revenues received would translate to anywhere between 12 to 23 cents on the dollar. Therefore, 17 cents on the dollar should not be used as a rule of thumb for mitigation of UDC costs going forward.

b) A starting point for determining the fair market value of transportation in the secondary market would normally be the price spread between the two points in question. In this case one would use the price spread, otherwise known as basis, between Empress and Dawn. However, before discussing available market data it must be understood that, regardless of the basis, if there is no third party demand for the transportation then no transaction will occur. Reviewing historical price data only provides the final settled prices on a day. Gas trades throughout the day and prices at the two points in question, and thus basis, will fluctuate up and down during intraday trading. Therefore, depending on when during the day a transaction is entered into with a third party, the basis upon which the transaction is based may be higher or lower than the basis quoted at the end of a particular gas day.

Witnesses: J. Leblanc
D. Small

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Unaccounted For Gas Variance Account

Ref: ExC1/T2/S1/Table 1

Table 3 shows that the 2014 UAF volume is at the greatest amount (now at a 23 year high). Enbridge says that UAF is at 1.08% of sendout volume.

a) Does Enbridge have any information to show how it compares to other gas distributors on UAF? If so, please file it.

RESPONSE

a) The latest information available, representing a broad sample of the industry, is from the American Gas Association ("AGA") as released in July 2014 through its Financial and Operational Information Series ("FOIS"). In it, the AGA reported Lost and Unaccounted for Gas from 2012 at 0.88% of total volumes. Data for 2013 will be available in August 2015.

Witness: M. Suarez

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Customer Care CIS Rate Smoothing Deferral Account

Ref: ExC1/T1/S10/

The Company wishes to clear the interest amounts accumulated in the account now, but not the principal amounts.

a) What is the reason for the request for interest clearance now as opposed to waiting until the remainder of the balance is due for clearance?

RESPONSE

The Company is requesting clearance of the interest balances on the Customer Care CIS Rate Smoothing Deferral Accounts ("CCCISRSDA") in accordance with the terms of the Board-Approved EB-2011-0226 Settlement Agreement, which specified that interest on the balance recorded in the account would be cleared annually at the same time as Enbridge's other deferral and variance accounts are cleared. (See EB-2011-0226, Exhibit N1, Tab 1, Schedule 1, page 24)

The EB-2011-0226 Settlement Agreement also specified that the principal balances would not be cleared during the 2013 through 2018 period, because the cumulative balance will build up during the years 2013 to 2015 when the approved cost per customer exceeds the smoothed cost per customer being collected in rates, and then be drawn down during the years 2016 to 2018 when the approved cost per customer is lower than the smoothed cost per customer being collected in rates. As a result, it is expected that the cumulative balance in the CCCISRSDA at the end of 2018 will either be zero and not require clearance, or a small debit or credit, which per the terms of the EB-2011-0226 Settlement Agreement will be cleared along with other 2018 deferral and variance accounts (likely in 2019).

In contrast to the cumulative principal balance in the CCCISRSDA which is expected to be zero or small at the end of 2018, the cumulative interest receivable balance will continue to grow throughout the 2013 through 2018 term because the net principal balance is expected to be in a debit position until the end of 2018 (at which point it is expected to be zero or a small debit or credit). This is due to the fact the cumulative debit/receivable recorded in 2013 through 2015, when the approved cost per customer exceeds the smoothed cost per customer being collected in rates, will not be fully offset until the end of 2018. Given that the net interest balance is expected to be in a receivable position throughout the 2013 through 2018 term, it was determined to be appropriate to collect the balance on an annual basis. (Again, see EB-2011-0226, Exhibit N1, Tab 1, Schedule 1, page 24)

Witnesses: D. McIlwraith
R. Small

BOARD STAFF INTERROGATORY #5

INTERROGATORY

Clearance of DDCTDA & UDCDA

Ref: ExC/T2/S1/ para 10

The Company wishes to clear the balance of both the 2014 DDCTDA and 2014 UDCDA accounts based on the deliverability allocator.

"The UDC costs that comprise the balance of the UDCDA and DDCTDA represent the unutilized portion of the long haul FT capacity that the Company acquired for load balancing purposes. To represent cost causality, the Company proposes to clear the balance of both accounts to all bundled customers (system gas and direct purchase customers) based on the deliverability allocator under the Board approved cost allocation and rate design methodology."

a) Has Enbridge cleared similar types of balances in the past? (for example, peaking services costs). If so, what clearance methodology was used for these accounts? Please provide examples of the relevant cases where the OEB accepted clearances of similar cost type using a similar methodology.

RESPONSE

Enbridge has not cleared a UDC-related deferral account in the past; however, the treatment proposed in this application is consistent with the Company's treatment of peak-related costs in its cost allocation and rate design process. The Deliverability allocator represents each customer class' load balancing needs in peak or near peak conditions. Costs associated with services employed to meet peak or near peak conditions are allocated to the various rate classes using the Deliverability allocator. For example, costs of storage deliverability, the recovery of curtailment credits from non-interruptible customers, and costs of short-term peaking supplies are allocated on the basis of Deliverability of each customer class. The allocation of peak-related costs can be identified in EB-2014-0276, Exhibit G2, Tab 5, Schedule 3, Lines 2.1 and 3.1. Costs on both these lines are allocated using the Deliverability allocator that can be found in the same proceeding, Exhibit G2, Tab 6, Schedule 3, Line 3.1.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

Price variances in the PGVA for peak supplies are cleared to customers quarterly through the QRAM process using the same methodology. In EB-2015-0163 (the July QRAM), at Exhibit Q3-3, Tab 3, Schedule 2, page 1, Line 1.2, peak-related costs are allocated using the Deliverability allocator (found at Schedule 4, Line 3.1 of the same proceeding). The methodology is also evident in the PGVA clearance schedules in the July QRAM, found at Tab 4, Schedule 8, Pages 14 and 15, where the Deliverability allocator is used to clear the balance of the Peaking Supplies and Curtailment Revenue accounts.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

BOMA INTERROGATORY #6

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 2, Page 6

Is EGD asking for approval to clear the ISDCDA and DDCTDA April 30th balances in October 2015, or not? BOMA finds the sentence at Page 6 confusing.

RESPONSE

The Company presumes that the reference to "ISDCDA" was intended to be the UDCDA.

At Exhibit C, Tab 1, Schedule 2, page 6 the Company indicated that the balance of the DDCTDA, including applicable interest, would be disposed of in a manner designated by the Board in a future rate proceeding. The reference to a future rate proceeding was intended to mean clearance of the 2014 DDCTDA (and the 2014 UDCDA) as part of the October 2015 QRAM proceeding along with the other deferral accounts that the Company is seeking to dispose of as part of this proceeding.

Please see also the responses to CCC Interrogatory #4 (I.C.EGDI.CCC.4) and FRPO Interrogatory #8 (I.C.EGDI.FRPO.8).

Witnesses: J. Leblanc
D. Small
R. Small

BOMA INTERROGATORY #7

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 2, Page 3 of 6

Please explain fully with reference to the amounts in each of the 20 deferral accounts that are being cleared, the allocation of the balance in each of the accounts, whether credit, or debit, to the various rate classes as shown on the two tables on this page. Please provide the underlying rationale, or drivers, for the allocation of each account and the subsequent conclusions to allocate to those rate classes.

RESPONSE

The intention of the allocation methodology used to clear deferral and variance account balances is to mimic the treatment of such costs in the Company's rates which are derived through the cost allocation and rate design process. Exhibit C, Tab 2, Schedule 2, page 3, shows the classification and allocation of amounts in each of the accounts the Company is proposing to clear in this application. Column 1 shows the balance to be cleared in each account. Columns 2 through 10 show the cost driver for allocation of each account's balance.

For example, Line 2, the Unaccounted for Gas ("UAF") variance account, is classified to Column 4, the Total Deliveries allocator. The UAF costs are recovered in the Company's rates based on the Total Deliveries allocator. As such, allocating the balance of the UAFVA using the Total Deliveries allocator ensures that the account balance is cleared in the same manner as the UAF are recovered in the Company's rates.

As a second example, Line 20, Earnings Sharing Mechanism, is classified to Column 10, the Rate Base allocator. The allocation of earnings sharing needs to reflect utility operations as a whole, and the Rate Base allocator is the most comprehensive representation of the total utility costs to each rate class.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

BOMA INTERROGATORY #8

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 1, Page 3

With respect to the two new accounts, DDCTDA and ISDCDA:

(a) Please provide the Board-approved or proposed definition of each account. How are expenditures allocated between them. Please explain what goes into each account.

(b) Please provide the reasoning underlying the extent to which each allocation factor for the two accounts is used to allocate the costs among the various rate classes.

(c) Please clarify that the "deliverability" allocator mentioned at Page 4 represents rate class design day demand in excess of the class's average winter demand, or if not, what is the allocator. Please explain fully.

RESPONSE

a) A definition of the 2014 DDCTDA and the 2014 UDCDA can be found as a part of the Final Accounting Order in EB-2012-0459, Appendix A, pages 11 to 14. For a description of the amounts that go in to each account please see response to Board Staff Interrogatory #1 (Exhibit I.C.EGDI.STAFF.1).

b) The reasoning underlying the Company's proposal to clear the balance of both accounts to all bundled customers based on the Deliverability allocator is provided in the referenced exhibit. As described in that exhibit, "the UDC costs that comprise the balance of the UDCDA and DDCTDA represent the unutilized portion of the long haul FT capacity that the Company acquired for load balancing purposes." The Deliverability allocator represents each customer class' load balancing needs in peak and near peak conditions. See also the response to Board Staff Interrogatory #5 (Exhibit I.C.EGDI.STAFF.5).

Witnesses: J. Collier
A. Kacicnik
M. Kirk
D. Small
R. Small

c) Confirmed. The Deliverability allocator represents rate class peak demand in excess of the class' average winter demand. The calculation for the Deliverability factor is as follows:

$$\text{Deliverability} = \text{Peak Day Demand} - \frac{\text{Total Winter Demand}}{151^{*}}$$

* 151 represents the number of days in winter, therefore this fraction is equal to average winter daily demand.

Witnesses: J. Collier
A. Kacicnik
M. Kirk
D. Small
R. Small

CCC INTERROGATORY #3

INTERROGATORY

Ex. C/T1/S1/p. 3

What is the cause of the balance in the MGPDA? Why is EGD not seeking to clear the balance at this time?

RESPONSE

Please see the response to Part a) of Energy Probe Interrogatory #9, found at Exhibit I.C.EGDI.EP.9.

Witness: R. Small

CCC INTERROGATORY #4

INTERROGATORY

Ex. C/T1/S2/p. 6

Please explain why EGD is not proposing to clear the balance in the DDCTDA.

RESPONSE

Enbridge is proposing to clear the balance in the DDCTDA, as seen at Exhibit A, Tab 2, Schedule 1, Appendix A, Line 17.

At Exhibit C, Tab 1, Schedule 2, page 6 the Company indicated that the balance, including applicable interest, would be disposed of in a manner designated by the Board in a future rate proceeding. The reference to “manner” was meant to relate to the way that the balance of the 2014 DDCTDA (and the 2014 UDCDA) would be cleared. The reference to a future rate proceeding was intended to mean the October 2015 QRAM proceeding where Enbridge expects to clear these accounts, along with the other deferral accounts that the Company is seeking to dispose of as part of this proceeding.

Please see also the responses to BOMA Interrogatory #6 (I.C.EGDI.BOMA.6) and FRPO Interrogatory #8 (I.C.EGDI.FRPO.8).

Witnesses: J. LeBlanc
D. Small

CCC INTERROGATORY #5

INTERROGATORY

Ex. C/T1/S7

How are the costs associated with the GDAR Low Income Customer Service Rule changes recovered (from which ratepayers)?

RESPONSE

Costs associated with the GDAR Low Income Customer Service Rule changes are allocated to the various rate classes in proportion to the number of customers in each rate class. This process can be identified in the table found at Exhibit C, Tab 2, Schedule 2, page 3. Line 10 of the table shows Gas Distribution Access Rule D/A 2014, equal to $152.7 thousand, classified to "Number of Customers" in Column 9. This allocation is consistent with the treatment of other GDAR costs.

Witnesses: M. Kirk
D. McIlwraith
R. Small

CME INTERROGATORY #4

INTERROGATORY

C. Deferral and Variance Accounts

(1) The 2014 Design Day Criteria Transportation Deferral Account ("DDCTDA")

The evidence at Exhibit C, Tab 1, Schedule 2 indicates that embedded within EGD's Board approved 2014 rates were STFT and FT components of its 2014 Gas Supply Portfolio which were required to enable the company to meet its peak day requirement. In connection with this evidence, please provide the following information:

(a) What was the 2014 forecasted peak day requirement?

(b) What were the 2014 forecasted costs of meeting that requirement which were embedded in Board approved 2014 rates?

(c) What was the unit amount forecast to be recovered for this particular component of EGD's Board approved rates under the auspices of the Board approved throughput of 11,159.1 $10^6 m^3$ shown at Exhibit B, Tab 3, Schedule 2, Column 2, line 5?

RESPONSE

To clarify, the evidence at Exhibit C, Tab 1, Schedule 2 provided background as to the reasons why the Company **did not** include STFT as a component of its 2014 Gas Supply Portfolio.

a) The 2014 forecasted Peak Day Requirement was filed in EB-2012-0459 Exhibit D3, Tab 3, Schedule 3, page 1, Updated 2013-10-29. A copy is attached as Attachment 1.

b) For purposes of developing its gas supply portfolio for a particular year, the Company will forecast a design day peak day demand to determine the assets i.e., transportation, storage, curtailment required to meet that peak day demand. The next step is then to determine the optimum use of those assets to meet the daily demand throughout the year. Once the supply portfolio for the year is established, the annual gas cost forecast is developed. The 2014 Gas Cost forecast was filed in Exhibit D3, Tab 3, Schedule 1 in EB-2012-0459. Once the

Witnesses: J. LeBlanc
D. Small

supply portfolio is approved by the Board, then it will be used for purposes of developing the QRAM applications throughout the year.

c) As part of the Cost Allocation and Rate Design process, the total gas cost forecast representing the annual cost of EGD's gas supply plan identified in part b) above is broken down into the various components i.e., commodity, transportation and load balancing which would include Peak. This breakdown can be found at EB-2012-0459, Exhibit G2, Tab 6, Schedule 2, a copy of which is attached as Attachment 2.

Total Peak and Seasonal costs listed in Line 9, Columns 7 and 8, respectively, are used to set Load Balancing rates. Load Balancing unit rates by rate class are not determined on a service or asset level but instead on a gas supply portfolio basis, in accordance with how the Company meets its customers' load balancing requirements. These rates vary across rate classes based on the load balancing requirements of each customer class. For example, low load factor customers, such as Rate 1 residential customers, require more load balancing than high load factor customers and would, therefore, be charged a higher load balancing rate.

	2013 Budget Peak Day Demand	Column 1	Column 2	Column 3	2014 Budget Peak Day Demand	Column 4	Column 5	Column 6
Item #	GJ's	CDA	EDA	Total	GJ's	CDA	EDA	Total
1.	Demand	3,229,260	592,864	3,822,124	Demand	3,288,088	673,262	3,961,350
2.	Less Curtailment	(129,737)	(31,788)	(161,524)	Less Curtailment	(133,995)	(28,705)	(162,700)
3.		3,099,523	561,076	3,660,600		3,154,093	644,557	3,798,650
4.	TCPL FT Capacity	63,468	197,421	260,889	TCPL FT Capacity	271,468	370,627	642,095
5.	TCPL STFT	302,500	90,000	392,500	TCPL STFT	-	-	-
6.	TCPL Short Haul	147,318	114,000	261,318	TCPL Short Haul	151,818	114,000	265,818
7.	TCPL STS	369,464	80,611	450,076	TCPL STS	369,464	80,611	450,075
8.	Ontario T-Service	308,176	28,137	336,313	Ontario T-Service	300,354	26,576	326,930
9.	Union Deliveries	1,775,027	-	1,775,027	Union Deliveries	1,775,027	-	1,775,027
10.	Delivered Service	32,753	-	32,753	Delivered Service	182,738	-	182,738
11.	Peaking Service	105,505	52,753	158,258	Peaking Service	105,505	52,753	158,258
12.	Total Supply	3,104,212	562,922	3,667,134	Total Supply	3,156,374	644,567	3,800,941
13.	Sufficency/(Deficiency)	4,688	1,846	6,535	Sufficency/(Deficiency)	2,281	10	2,291

CLASSIFICATION OF GAS COSTS TO OPERATIONS

Item No.	Description	Col. 1 Annual Volumes (10^3m^3)	Col. 2 Variable Unit Rate $/($10^3m^3$)	Col. 3 Variable Cost $(000)	Col. 4 Deliver-ability $(000)	Col. 5 Seasonal Space $(000)	Col. 6 Winter $(000)	Col. 7 Peak $(000)	Col. 8 Seasonal $(000)	Col. 9 Annual $(000)	Col. 10 Dist'n. Commodity $(000)	Col. 11 Total $(000)
		System Commodity			Load Balancing: Storage			Load Balancing: Pipeline				
	Purchases and Receipts											
1.1	Long-Term	730.0	120.8	88.2	0.0	0.0	0.0	0.0	0.0	38.7	0.0	126.9
1.2	Western Buy/Sell	1,326.7	120.8	160.3	0.0	0.0	0.0	0.0	0.0	1.8	0.0	162.0
1.3	Ontario Buy.Sell	0.0	120.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.4	Short-Term Annual	0.0	120.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Short-Term Peak	36,068.0	120.8	4,357.4	0.0	0.0	0.0	3,984.7	0.0	0.0	0.0	8,342.0
1.6	Discretionary Western & US	6,607,724.1	120.8	798,279.1	0.0	0.0	0.0	0.0	0.0	41,742.2	0.0	840,021.3
1.7	Discretionary - Ontario	924,668.5	120.8	111,709.2	0.0	0.0	0.0	11,505.2	2,477.0	10,245.3	0.0	135,936.7
1.	Total Purchases & Receipts	7,570,517.3	120.8	914,594.2	0.0	0.0	0.0	15,489.9	2,477.0	52,027.8	0.0	984,588.9
	Transportation											
2.1	TCPL FT-Demand System	0.0	0.0	0.0	0.0	0.0	0.0	11,640.6	0.0	243,576.5	0.0	255,217.1
2.2	Unutilized Transport Costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2.3	Alliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38,358.7	0.0	38,358.7
2.4	Vector	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55,515.2	0.0	55,515.2
2.5	Nova	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,200.4	0.0	6,200.4
2.	Total Transportation	0.0	0.0	0.0	0.0	0.0	0.0	11,640.6	0.0	343,650.8	0.0	355,291.4
	Other Costs											
3.1	Fuel	0.0	0.0	9,136.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,136.8
3.	Total Other Variable Costs	0.0	0.0	9,136.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,136.8
4.	**Total Delivered Supply**	7,570,517.3	0.0	923,731.0	0.0	0.0	0.0	27,130.5	2,477.0	395,678.6	0.0	1,349,017.1
5.	**Storage Fluctuation**	(86,272.7)	120.8	(10,800.2)	0.0	0.0	0.0	(267.6)	(24.4)	(3,903.5)	0.0	(14,995.7)
6.	**Gas Costs to Operations**	7,484,244.5	0.0	912,930.8	0.0	0.0	0.0	26,862.8	2,452.6	391,775.2	0.0	1,334,021.5
7.	**Storage and Transportation**	0.0	0.0	0.0	98,003.8	56,687.5	0.0	0.0	0.0	0.0	0.0	154,691.2
8.	**Gas Costs-Storage & Trans.**	7,484,244.5	0.0	912,930.8	98,003.8	56,687.5	0.0	26,862.8	2,452.6	391,775.2	0.0	1,488,712.7
9.	**Total Classified Costs**			896,692.1	98,003.8	56,687.5	0.0	26,608.7	2,429.4	387,728.4	16,432.3	1,484,582.2
	GAS COSTS											
10.1	Classification Factors			896,692.1	0.0	0.0	0.0	26,608.7	2,429.4	387,728.4	16,432.3	1,329,890.9
10.2	Classification Percentages			67.43%	0.00%	0.00%	0.00%	2.00%	0.18%	29.15%	1.24%	100.00%
	STORAGE											
11.1	Classification Factors				98,003.8	56,687.5	0.0	0.0	0.0	0.0	0.0	154,691.2
11.2	Classification Percentages				63.35%	36.65%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%

Witnesses: A. Kacicnik
M. Kirk

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	6,010.4	6,010.4	0.0	6,010.4	0.0	0.0
1.2	Daily Demand	10,978.3	10,978.3	10,978.3	0.0	0.0	0.0
1.3	In/out	4,692.2	4,692.2	0.0	4,692.2	0.0	0.0
1.4	Fuel	3,152.0	3,152.0	0.0	3,152.0	0.0	0.0
1.5	Transactional Services Revenues	(3,413.6)	(3,413.6)	(2,048.2)	(1,365.5)	0.0	0.0
1.	Total Transmission	21,419.3	21,419.3	8,930.2	12,489.1	0.0	0.0
	STORAGE						
2.1	Annual Demand	5,761.3	5,761.3	0.0	5,761.3	0.0	0.0
2.2	Daily Demand	10,641.0	10,641.0	10,641.0	0.0	0.0	0.0
2.3	In/out	776.7	776.7	0.0	776.7	0.0	0.0
2.4	Transactional Services Revenues	(2,586.4)	(2,586.4)	(1,551.8)	(1,034.5)	0.0	0.0
2.	Total Storage	14,592.6	14,592.6	9,089.2	5,503.4	0.0	0.0
3.	Total Tecumseh	36,011.9	36,011.9	18,019.4	17,992.5	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		8,885.4	0.0	8,885.4	0.0	0.0
4.2	Peak		10,859.9	10,859.9	0.0	0.0	0.0
4.3	Injection		111.7	0.0	111.7	0.0	0.0
4.4	Withdrawal		69.5	0.0	69.5	0.0	0.0
	Chatham D		132.8	0.0	132.8	0.0	0.0
4.	Total Storage		20,059.3	10,859.9	9,199.4	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		63,095.6	39,314.3	23,781.3	0.0	0.0
5.4	Fuel		14,611.1	9,104.0	5,507.1	0.0	0.0
5.	Total Transmission		77,706.7	48,418.4	29,288.4	0.0	0.0
	DEHYDRATION						
6.1	Demand		1,010.8	1,010.8	0.0	0.0	0.0
6.2	Commodity		207.2	0.0	207.2	0.0	0.0
6.	Total Dehydration		1,218.0	1,010.8	207.2	0.0	0.0
7.	Total Union		98,984.0	60,289.1	38,695.0	0.0	0.0
	TRANSCANADA						
8.1	STS and Other		19,695.3	19,695.3	0.0	0.0	0.0
8.	Total TransCanada		19,695.3	19,695.3	0.0	0.0	0.0
9.	**TOTAL STORAGE & TRANSP.**		154,691.2	98,003.8	56,687.5	0.0	0.0
10.	**COST TO OPERATIONS**		154,691.2	98,003.8	56,687.5	0.0	0.0

Witnesses: A. Kacicnik
M. Kirk

CLASSIFICATION OF TRANSPORTATION COSTS

($000)

Item No.	Description	Col. 1 Total	Col. 2 Peak	Col. 3 Seasonal	Col. 4 Annual Delivery	Col. 5 Annual Commodity
	FT TCPL					
1.1	Demand	252,213.2	11,640.6	0.0	240,572.5	0.0
1.2	Commodity	3,004.0	0.0	0.0	3,004.0	0.0
1.3	Unutilized Transport. Cost	0.0	0.0	0.0	0.0	0.0
	Alliance					
2.1	Demand	38,358.7	0.0	0.0	38,358.7	0.0
2.2	Commodity	0.0	0.0	0.0	0.0	0.0
3	**Vector Demand**	55,515.2	0.0	0.0	55,515.2	0.0
4	**NOVA Demand**	6,200.4	0.0	0.0	6,200.4	0.0
	OTHER					
5.1	Fuel	9,136.8	0.0	0.0	0.0	9,136.8
6	**Total**	364,428.2	11,640.6	0.0	343,650.8	9,136.8

Witnesses: A. Kacicnik
M. Kirk

CME INTERROGATORY #5

INTERROGATORY

C. Deferral and Variance Accounts

(1) The 2014 Design Day Criteria Transportation Deferral Account ("DDCTDA")

The evidence indicates that actual 2014 throughput was 12,656.5 10^6m^3 as shown in line 5 of Column 1 in Exhibit B, Tab 3, Schedule 2, or 113.4% of Board approved throughput. This means that EGD actually recovered in rates about 113.4% of the forecast costs related to meeting its peak day requirement. In connection with this evidence, please provide the following additional information:

(a) What is the "over-recovered" amount, being 13.4% of the forecast amount embedded in Board approved rates?

(b) Please provide a step-by-step description and schedule which will show how the debit amount of $12,839.3 shown in Column 3, line 17 of Exhibit C, Tab 1, Schedule 1, page 3 was derived.

(c) In particular, please demonstrate that the derivation of this number takes into account the recovery in rates of additional costs related to this item as a consequence of actual throughput in 2014 exceeding Board approved throughput, by 13.4%.

(d) If that 13.4% amount has not been taken into account, then please adjust the $12,839.3 recorded in the 2014 DDCTDA to take into account the additional costs above forecast amounts actually recovered.

RESPONSE

a) The Company disagrees with the implication that the Company "over recovered" 13.4% merely because actual 2014 "throughput" was higher than Board approved throughput. Other cost items such as gas costs increased with a greater throughput.

The 2014 gas cost forecast included costs pertaining to a level of long haul transportation capacity utilization. Any costs associated with unutilized capacity were not included in the derivation of 2014 base rates. To the extent that demand

Witnesses: D. Small
R. Small
L. Stickles

in 2014 was higher than budget and the Company was able to utilize a level of what was forecasted as excess capacity, then the Company did so and thereby reduced the unutilized transportation costs and the associated UDC costs that would otherwise have been recorded in either the 2014 DDCTDA or the 2014UDCDA.

b), c) and d) Please see response to Board Staff Interrogatory #1 (Exhibit I.C.EGDI.STAFF.1).

Witnesses: D. Small
R. Small
L. Stickles

CME INTERROGATORY #6

INTERROGATORY

C. Deferral and Variance Accounts

(2) The 2014 Unabsorbed Demand Charge Deferral Account (“UDCDA”)

The evidence at Exhibit C, Tab 1, Schedule 1, page 3, line 18, Column 3 indicates that EGD seeks to recover a debit balance of $13,526.2M in the 2014 UDCDA. In connection with this evidence, please provide the following information:

(a) Are there 2014 UDC forecast volume and cost amounts embedded in 2014 Board approved rates? If so, then what are those amounts?

(b) Actual throughput in 2014 of 12,656.5 10^6m^3 was 113.4% of the Board approved throughput of 11,159.1 10^6m^3. If there are UDC forecast volume and cost amounts embedded in 2014 Board approved rates, then what are the amounts by which those embedded forecast amounts have been exceeded as a result of actual throughput being 113.4% of forecast throughput?

(c) Please provide a step-by-step description and schedule which shows how the debit amount of $13,526.2M of 2014 UDCDA was derived.

(d) In particular, please demonstrate that this number takes into account any recovery of actual costs in excess of the forecast costs of UDC embedded in rates as a result of actual 2014 throughput exceeding Board approved throughput.

(e) If such an amount has not been reflected in the calculation, then please adjust the $13,526.2M debit amount to take that amount into account.

RESPONSE

Please see response to CME Interrogatory #5 (Exhibit I.C.EGDI.CME.5).

Witnesses: D. Small
R. Small

CME INTERROGATORY #7

INTERROGATORY

C. Deferral and Variance Accounts

(3) Unaccounted for Gas ("'UFG")

In connection with the evidence at Exhibit C, Tab 1, Schedule 4 pertaining to the Unaccounted for Gas Variance Account claim of about $11.9M, please provide the following further information:

(a) What is EGD's 2014 Board approved forecast UFG allowance expressed as a percentage of Board approved 2014 throughput of 11,159.1 10^6m^3?

(b) What was the Board approved forecast dollar amount embedded in EGD's approved 2014 rates?

(c) What is EGD's 2014 actual UFG expressed as a percentage of actual throughput of 12,656.5 10^6m^3?

(d) What was the actual dollar amount of UFG recovered in 2014 as a consequence of actual throughput of 12,656.5 10^6m^3 exceeding Board approved throughput of 11,159.1 10^6m^3?

RESPONSE

a) The UAF allowance of 0.70% was approved and included within 2014 Approved Rates.

b) Based on the PGVA reference price approved in the 2014 decision (EB-2012-0459), approximately $13.5 million related to UFG costs were embedded in Enbridge Gas Distribution's Final 2014 rates. The corresponding forecast gas cost expense for UFG was also approximately $13.5 million.

   These numbers were subsequently updated from the new PGVA reference price within each QRAM application during 2014.

c) Enbridge Gas Distribution's actual UAF was 135,380 10^3m^3 which is 1.08% of actual sendout.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

d) The Company does not track or determine actual versus forecast recovery of each cost component recovered through the Company's rates.

The Company would like to emphasize that the balance recorded in the 2014 Unaccounted for Gas Variance Account (2014 UAFVA) reflects the purpose / accounting order for the UAFVA:

> The purpose of the 2014 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of unaccounted for gas ("UAF") and the 2014 Board approved UAF volumetric forecast.

The pivot point for the variance account is the cost of gas associated with UAF volumetric variances. This pivot point does not consider revenue variances that could be considered to have taken place with respect to UAF costs reflected in the Company's rates.

The cost exposure of the variance account is symmetric for customers and the Company.

The purpose / accounting order for the 2014 UAFVA reflects the experience that UAF volumetric variances (forecast versus actual) are not directly related or proportional to the changes / variances in volumetric throughput. UAF reflects the difference between the sendout volume (i.e., the volume that entered the Company's gas distribution network as measured by gate stations and billed to Enbridge by upstream transmitters) and the volume that was billed to customers (i.e., the volume that was consumed / metered at the customers' premises). Because of its residual nature, UAF cannot be measured directly and can arise from metering differences, operational and external factors. Temperature and pressure also contribute to metering variance affecting sendout versus billed volumes.

Witnesses: J. Collier
A. Kacicnik
M. Suarez

CME INTERROGATORY #8

INTERROGATORY

C. Deferral and Variance Accounts

(3) Unaccounted for Gas ("'UFG")

The evidence at Exhibit C, Tab 1, Schedule 4, page 1, question 4 suggests that the forecast UFG volume embedded in 2014 rates was 77.660 10^6m^3; (135.380 10^6m^3 minus 57.720 10^6m^3 = 77.660 10^6m^3). With actual 2014 throughput being 113.4% of Board approved throughput of 11,159.1 10^6m^3, EGD has already recovered in 2014 actual rates the costs associated with a UFG volume of 88.066 10^6m^3 (113.4% x 77.660 10^6m^3 = 88.066 10^6m^3) being 10,406 10^6m^3 more than the Board approved forecast UFG volume of 77.660 10^6m^3. These calculations indicate that the UFG variance account should only reflect costs associated with 47.364 106m3 (57.720 10^6m^3 — 10.406 10^6m^3 = 47.364 10^6m^3). This amount is some 82% of the volume of 57.720 10^6m^3 which has been used to derive the 11.9M recorded in the UFG variance account. These calculations indicate that the amount of $11.9M is some $2.2M too high. In connection with this evidence, please provide the following:

(a) A schedule and step-by-step description showing how the debit amount of $11,9M in the 2014 UAF was calculated; and

(b) If that amount does not reflect the additional UAF costs recovered as a consequence of actual 2014 throughput, being 113.4% of Board approved throughput, then adjust the $11.9M amount to reflect the actual recovery of UFG costs in 2014 in excess of the estimated costs embedded in rates.

RESPONSE

a) Please see the response to Energy Probe Interrogatory #10 part a) at Exhibit I.C.EGDI.EP.10.

b) Please see the response to CME Interrogatory #7, part d) at Exhibit I.C.EGDI.CME.7.

Witness: M. Suarez

ENERGY PROBE INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 1

a) Please explain why EGDI is not requesting clearance of the 2014 MGPDA account at this time, but rather transferring the balance to the 2015 account.

b) What is the projected balance in the CDNSADA at the end of 2018?

RESPONSE

a) There is no balance recorded in the 2014 Manufactured Gas Plant Deferral Account ("MGPDA"). The balance in the 2014 MGPDA has been transferred to the 2015 MGPDA in accordance with the Company's proposal/evidence supporting the 2015 MGPDA, contained within the EB-2014-0276 proceeding. The balance represents the accumulation of costs incurred since 2006, the year in which the account was first approved, which have been carried forward through to the current account balance. Most of the amounts recorded within the 2015 MGPDA arise from Enbridge's defense of a lawsuit brought by Cityscape Residential Inc. against the Company in relation to alleged contamination at a site in Toronto. During 2014, after a prolonged period of inactivity, the plaintiff acted to move the lawsuit forward. In response, Enbridge brought a motion to dismiss the case for delay. That motion has been adjourned while the parties engage in settlement discussions.

The rationale for rolling the 2014 MGPDA balance forward was that the majority of the costs contained within the account relate to the ongoing legal proceeding with Cityscape, which to this point has not achieved a resolution. The Company expects that it will seek clearance of the account upon completion of the Cityscape lawsuit, possibly as part of the 2015 or 2016 ESM/Deferral and Variance Account Clearance Proceeding. If resolution of the Cityscape lawsuit is not achieved, Enbridge may still seek clearance of the MGPDA balance in one of the above mentioned proceedings, depending on the magnitude of the amount recorded within the account. In any event, though, because the MGPDA relates to all of the Company's former MGP sites, it is anticipated that the MGPDA will continue beyond the time of any initial clearance and beyond the time that the Cityscape lawsuit is completed.

Witness: R. Small

b) The current balance in the Constant Dollar Net Salvage Adjustment Deferral Account ("CDNSADA"), as at June 30, 2015, is a receivable of $43,800.7 thousand. The balance reflects that a greater than planned credit to ratepayers (through Rider D), of previously collected net salvage reserve amounts, has occurred to date. The excess credit to ratepayers is a result of greater actual volumes, predominantly due to colder weather, than the forecast volumes upon which Rider D unit rates were developed. At this time, the Company has not produced an updated volumetric forecast for the remainder of 2015, and has no expectation that volumes will differ materially from the approved forecast, and therefore does not expect any material change from the current balance by year end. In addition, the Company has no reason to expect that the actual amounts that will be cleared in 2016 through 2018 will differ from the forecast amounts to be cleared in each of those respective years, as the volumetric forecast upon which Rider D will be developed will be updated annually. As a result, the current CDNSADA balance is the Company's best estimate of the balance at the end of 2018.

Witness: R. Small

ENERGY PROBE INTERROGATORY #10

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 4

a) Please explain how the value of $11.9 million was calculated based on the volumetric variance. Please show all calculations and provide all assumptions used. Is the value calculated using quarterly prices and volumes?

b) Please provide a graph, similar to Table 2, that shows the UAF as a proportion of total throughput.

RESPONSE

a) Please see the derivation of the $11.9 million balance which is attached to this interrogatory response.

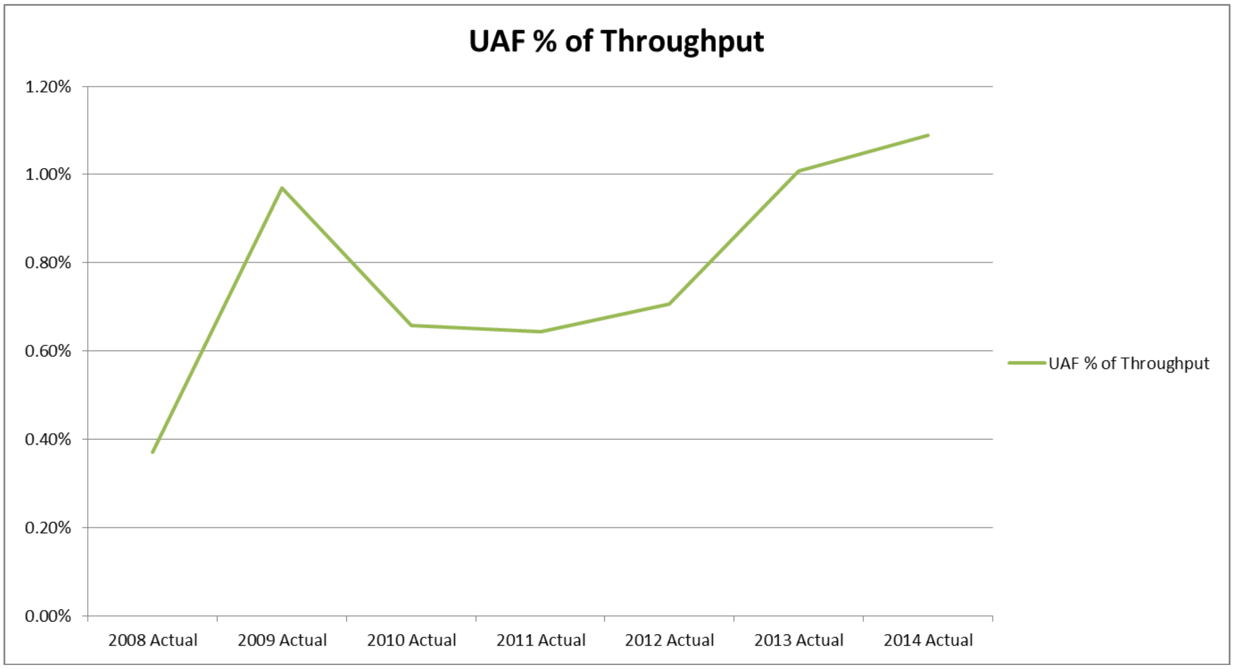
Confirmed. The derivation of the UAFVA balance takes into account quarterly PGVA reference prices and the variance between actual and forecast UAF volumes.

As per the accounting treatment for the UAFVA, “The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price.” Further, “Where there are recoveries of gas loss amounts invoiced as part of 3rd party damages, the gas loss amounts will be removed from the UAFVA balance.”

The net balance in the UAFVA reflects the cost of gas associated with the volumetric variances between the actual and forecast UAF volumes adjusted for gas lost amounts invoiced as part of 3rd party damages.

Witness: B. So
M. Suarez
L. Uhyrek

b)



Witness: B. So
M. Suarez
L. Uhyrek

Year 2014 UAFVA Calculation

		Col. 1 Jan	Col. 2 Feb	Col. 3 Mar	Col. 4 Apr	Col. 5 May	Col. 6 Jun	Col. 7 Jul	Col. 8 Aug	Col. 9 Sep	Col. 10 Oct	Col. 11 Nov	Col. 12 Dec	Col. 13 Total
Line 1	Forecast UAF (103m3)	13,513	13,691	11,583	8,228	4,616	2,222	1,617	1,723	1,990	3,056	5,790	9,633	77,660
Line 2	QRAM PGVA Reference Price	$ 182.04	$ 182.04	$ 182.04	$ 230.67	$ 230.67	$ 230.67	$ 230.67	$ 230.67	$ 230.67	$ 202.24	$ 202.24	$ 202.24	
Line 3	Forecast UAF Cost	$ 2,459,874	$ 2,492,314	$ 2,108,640	$ 1,897,882	$ 1,064,805	$ 512,473	$ 372,919	$ 397,370	$ 458,935	$ 618,056	$ 1,170,993	$ 1,948,068	$ 15,502,331
Line 4	Actual UAF (103m3)	22,397	22,145	20,581	15,139	8,939	4,869	3,825	4,173	3,828	5,148	10,594	13,742	135,380
Line 5	QRAM PGVA Reference Price	$ 182.04	$ 182.04	$ 182.04	$ 230.67	$ 230.67	$ 230.67	$ 230.67	$ 230.67	$ 230.67	$ 202.24	$ 202.24	$ 202.24	
Line 6	Actual UAF Cost	$ 4,077,216	$ 4,031,358	$ 3,746,659	$ 3,492,168	$ 2,061,875	$ 1,123,183	$ 882,223	$ 962,557	$ 882,949	$ 1,041,148	$ 2,142,456	$ 3,171,235	$ 27,615,027
Line 7	UAF Variance (Line 6 - Line 3)	$ 1,617,341	$ 1,539,044	$ 1,638,019	$ 1,594,286	$ 997,070	$ 610,710	$ 509,304	$ 565,187	$ 424,014	$ 423,092	$ 971,464	$ 1,223,167	$ 12,112,696
Line 9	2014 Damages Adjustment													$ (251,065)
Line 10	Total 2014 UAFVA													$ 11,861,631

Witness: B. So
M. Suarez
L. Uhyrek

FRPO INTERROGATORY #7

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 1, Page 3

For the Net Salvage Value adjustment, please provide a forecast for the 2018 values and the expected true-up.

RESPONSE

Please refer to the response to Part b) of Energy Probe Interrogatory #9, found at Exhibit I.C.EGDI.EP.9.

Witness: R. Small

FRPO INTERROGATORY #8

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 2, Page 6

What is EGD proposal for disposing of the balance?

a) If there is no proposal at this time, what is EGD proposed approach to establishing this disposition methodology?

RESPONSE

Enbridge Gas Distribution Inc. is proposing that the balance in the 2014 DDCTDA and the 2014 UDCDA and applicable interest be disposed of as part of the October 2015 QRAM.

Please see also the responses to BOMA Interrogatory #6 (I.C.EGDI.BOMA.6) and CCC Interrogatory #4 (I.C.EGDI.CCC.4).

Witnesses: J. LeBlanc
D. Small

FRPO INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C, Tab 1, Schedule 2, Page 6

Given the experience of last year and improvements implemented for 2015, what is the company's forecast for 2015 balances for UDC (including a recognition of any forecast transport yet to be shed in 2015).

RESPONSE

Pursuant to the EB-2012-0459 Decision, as a part of its ongoing monthly reporting commitments, the Company provides a forecast of the 2015 UDCDA. A copy of the June 2015 report is attached.

Witnesses: J. LeBlanc
D. Small

500 Consumers Road
North York ON M2J 1P8
P.O. Box 650
Scarborough, ON
M1K 5E3

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance
Tel 416-495-5499 or 1-888-659-0685
Fax 416-495-6072
Email egdregulatoryproceedings@enbridge.com

June 30, 2015

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. 2014 to 2018 Rate Application
Ontario Energy Board File No. EB-2012-0459 / EB-2014-0276

As per the Settlement Agreement in EB-2012-0459 (Exhibit N1, Tab 2, Schedule 1, page 6 of 19) the Company committed to provide a report to the parties of the Settlement Agreement to allow for the ongoing monitoring of UDC impacts in 2014.

The Company, as part of its 2015 Rate Application (EB-2014-0276, Exhibit D1, Tab 2, Schedule 1, page 6 of 11) committed to continue to provide monthly reporting in 2015. Also, the Company developed and filed a 2015 UDC Mitigation Strategy as part of the Supplemental Agreement in EB-2014-0276 and committed to file monthly updates to that mitigation strategy (Ex. N, Tab 1, Schedule 2, page 6, paragraph 4). Please see the attached Report for June 2015.

Please do not hesitate to contact me with any questions.

Yours Truly,

(Original Signed)

Andrew Mandyam
Director, Regulatory Affairs and Financial Performance

Attach.

cc: EB-2014-0276 Interested Parties

June 2015 Report

Demand	Actual January	Actual February	Actual March	Actual April	Estimate May	Estimate June	Budget July	Budget August	Budget September	Budget October	Budget November	Budget December	
PJ's	85.1	86.2	64.7	37.6	18.2	15.4	13.4	13.3	15.0	27.3	41.7	60.6	478.7

Forecasted Monetary Impacts
$ millions

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	6.6	7.9	12.0	13.7	13.7	12.8	17.3	12.2	12.2	108.2
Revenue From Unutilized Capacity Released													
- Seasonal	-	-	-	(1.2)	(1.6)	(2.2)	(2.7)	(2.7)	(2.6)	(2.7)	-	-	(15.6)
- Monthly				(0.6)	-	-	-	-	-	-	-	-	(0.6)
- Daily				(0.1)	(0.4)	(0.6)	-	-	-	-	-	-	(1.1)
Net Impact on Deferral Account	-	-	-	4.7	5.8	9.2	11.0	11.0	10.2	14.7	12.2	12.2	91.0

Forecasted Monthly Unutilized Capacity by Delivery Area
PJ's -

	January	February	March	April	May	June	July	August	September	October	November	December	
UDCDA	-	-	-	3.3	3.9	6.0	7.0	7.0	6.3	8.8	6.0	6.2	54.5
Unutilized Capacity Released													
- Seasonal	-	-	-	(2.2)	(3.1)	(4.5)	(5.5)	(5.5)	(5.3)	(5.5)	-	-	(31.6)
- Monthly	-	-	-	(0.8)	-	-	-	-	-	-	-	-	(0.8)
- Daily	-	-	-	(0.3)	(0.8)	(1.5)	-	-	-	-	-	-	(2.5)
Net Unutilized Capacity	-	-	-	-	-	-	1.5	1.5	1.0	3.4	6.0	6.2	19.6

Discretionary Requirement

	January	February	March	April	May	June	July	August	September	October	November	December	
PJ's	13.6	22.2	6.8	-	0.0	0.0	-	-	0.0	-	-	3.1	45.8

Month end Storage Capacity Target												
% Fill	0.53	0.37	0.20	0.17	0.26	0.42	0.59	0.77	0.92	1.00	0.93	0.72
Bcf	60.56	42.57	22.64	19.08	29.56	47.69	68.06	88.50	106.01	113.00	106.21	82.42

Month end Storage Capacity					
% Fill	0.52	0.34	0.17	0.16	0.32
Bcf	59.91	38.85	19.07	18.22	36.43

2015 Summer UDC Management Plan

Item #	PJ's	Column 1 April (actual)	Column 2 May (estimate)	Column 3 June (estimate)	Column 4 July (forecast)	Column 5 August (forecast)	Column 6 September (forecast)	Column 7 October (forecast)	Column 8 Total
	Days in the month	30	31	30	31	31	30	31	214
1.	Forecasted UDC To Be Mitigated	9.8	8.5	8.3	8.5	8.5	8.6	8.8	61.0
2.	Forecasted Dawn Discretionary Requirement Replaced with Utilization of Long Haul Capacity	0.0	0.0	-	-	-	-	-	0.0
3.	Potential UDC Shed	9.7	8.5	8.3	8.5	8.5	8.6	8.8	61.0
4.	Forecasted Added Utility Requirement	6.4	4.6	2.3	1.6	1.6	2.3	-	18.6
5.	Forecasted Summer Unutilized Capacity	3.3	3.9	6.0	7.0	7.0	6.3	8.8	42.3
6.	April to October Release	2.2	2.3	2.2	2.3	2.3	2.2	2.3	16.0
7.	April Capacity Released for the month	0.8							0.8
8.	April Capacity Released on the day	0.3							0.3
9.	May to October Release	-	0.8	0.8	0.8	0.8	0.8	0.8	4.9
10.	May Capacity Released on the day	-	0.8						0.8
11.	June to October Release	-	-	1.5	1.6	1.6	1.5	1.6	7.7
12.	June Capacity Released on the day			1.5					1.5
13.	July to October Release	-	-	-	0.8	0.8	0.8	0.8	3.1
14.	Remaining Daily/Monthly Release Capacity	(0.0)	(0.0)	-	1.5	1.5	1.0	3.4	7.4
15.	Total Targeted Daily Capactiy to be Released Daily/Monthly	-	(0)	-	48,560	48,560	33,560	108,560	

notes: -

Item # 11 - The UDC Mitigation Strategy assumed a June to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release 50,000 GJ's per day for the June to October period

Item # 13 - The UDC Mitigation Strategy assumed a July to September release of approximately 25,000 GJ's per day. Based upon a review of its summer injection schedule the Company determined that it could release this amount for the July to October period

FRPO INTERROGATORY #10

INTERROGATORY

Ref: Exhibit C, Tab 2, Schedule 1, Page 4

Please confirm that this approach is consistent with how the costs of the firm transport and load balancing are put into rates.

RESPONSE

Confirmed.

As stated in the referenced exhibit, "the Company utilizes a certain amount of long haul FT … to meet demand in peak and near-peak conditions." This indicates that some amount of firm transport costs needs to be classified as peak-related to reflect cost causality. Amounts classified as peak-related are allocated to the various rate classes using the Deliverability allocator and recovered through the Company's load balancing rates.

The referenced exhibit goes on to specify that "the UDC costs that comprise the balance of the UDCDA and DDCTDA represent the unutilized portion of the long haul FT capacity that the Company acquired for load balancing purposes." As such, the balances of the UDCDA and DDCTDA are cleared using the Deliverability allocator to maintain cost causality.

The Deliverability allocator represents each customer class' load balancing needs in peak or near-peak conditions.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

VECC INTERROGATORY #3

INTERROGATORY

Reference: C/T1/S2/pg.5 (PDF pg. 109)

a) EGD explains that the cost of unutilized capacity was $31.7 million and that it was successful in releasing 100% of this to third parties to generate revenues of $5.3 million. Please explain why the capacity was so highly discounted.

RESPONSE

The revenues Enbridge received from third parties for the release of long haul transportation capacity were indicative of the value for said service in the marketplace. The value for the transportation would be representative of the price spreads between Empress and Dawn during the summer months at the time the capacity was released.

Please see response to Board Staff Interrogatory #2 (Exhibit I.C.EGDI.STAFF.2) for a discussion of the factors that impact the value of transportation capacity in the secondary market.

Witnesses: J. Leblanc
R. Small

BOMA INTERROGATORY #9

INTERROGATORY

Ref: Exhibit D, Tab 1, Schedule 3

(a) Does EGD have fixed price contracts for both the Technology supplier, and the System Integrator?

(b) What is the role of the system integrator?

(c) How will it work with the technology supplier and EGD?

(d) Does the Fixed Fee for the build contract currently being negotiated cover all aspects of the project?

(e) Has the contract been signed? Can it be provided when signed? Please explain fully.

(f) Has any part of the project been put in rate base in 2014? When does EGD intend to place the project in rate base?

RESPONSE

a) Yes, Enbridge Gas Distribution has entered into fixed price contracts for the licenses of the technology components. For the Build Phase, Enbridge has entered into fixed price contracts with the vendors who are responsible for configuration of the Maximo and Click technologies.

b) The primary role of the vendors is to build and configure the respective technology components in a manner that meets Enbridge Gas Distribution's business requirements.

c) The technology supplier role is mainly limited to providing the technology for Enbridge's use.

Witnesses: W. Akkermans
B. Misra

d) No. The fixed fee for the build contract covers the configuration of the Maximo and Click Schedule technology components only. Other components such as training, organizational change management and downstream interface work will be completed by others, including Enbridge Gas Distribution.

e) Yes, all contracts have been signed. The Company will not be filing the contracts, as they are not relevant to relief being sought in this proceeding. Moreover, the contracts contain confidential and commercially sensitive information which is not appropriately disclosed in a public forum.

f) No. The intent is to put the cost associated with WAMS into ratebase in 2016 after it goes live and is being used.

Witnesses: W. Akkermans
B. Misra

BOMA INTERROGATORY #10

INTERROGATORY

Ref: Exhibit D, Tab 1, Schedule 2

How much, and which of, the expenditures on the GTA project have been entered into rate base in 2014?

RESPONSE

No costs in relation to the GTA project were included in rate base, as at the end of 2014.

Witnesses: S. Dodd
O. Schneider
R. Small

BOMA INTERROGATORY #11

INTERROGATORY

Ref: Exhibit D, Tab 1, Schedule 4

Why was it determined that the pipeline needed to be re-laid; was this determined only when construction began?

RESPONSE

The Innes Road pipeline was included in the original 10 year In Line Inspection ("ILI") program in 2003 for pipelines operating at or above 30% SMYS. Detailed analysis of the retrofits required to enable this line to be inspected using ILI determined that the retrofits were extremely complicated and extensive. Therefore it was decided to replace the Innes Road pipeline utilizing materials that would enable the operation of the line below the 30% SMYS thereby eliminating the requirement for ILI.

The replacement project was subject to the Leave to Construct process and was approved by the Board in 2013. The project was originally scheduled to be constructed in 2013, however, due to some permitting and pipeline alignment delays, the project was constructed in 2014.

Witnesses: D. Broude
D. Lapp

BOMA INTERROGATORY #12

INTERROGATORY

Ref: Exhibit D, Tab 1, Schedule 6

1. (a) Could you please provide a copy of, or a link to, ISO-55000 (January 15, 2014 release)?

   (b) What are the operating, and capital, IRM budgets and FTEs for the Asset Management project?

   (c) Who is the recently appointed Director of Asset Management?

   (d) Please provide a copy of the Operational Risk Assessment Standard acquired.

   (e) What is the Asset Planning Tool and who is the Vendor? Please provide a description of the Asset Planning Tool.

RESPONSE

a) Enbridge Gas Distribution is using a copy of ISO-55000:2014. This standard can be purchased directly from ISO (http://www.iso.org/iso/home.html) or from the Institute of Asset Management (https://theiam.org/).

b) There were no amounts budgeted for this new Asset Management project within the IRM budgets.

   There is currently no operating budget for the project.

   The Capital budget for the project is:

   $2,600,000 under the System Integrity and Reliability ("SIR") budget
   $1,534,000 under the IT budget

   There are 16 FTEs on the Asset Management Project including Asset Analytics, Risk Management, and Portfolio Optimization

Witness: T. MacLean

c) Trevor MacLean was appointed Director of Asset Management effective January 5, 2015.

d) Enbridge Gas Distribution has developed a draft of an Operational Risk Assessment Standard. The purpose of this document is to set down the vision and principles that are to be followed to produce and test risk assessment tools to meet applicable internal and external requirements. The vision comprises a set of desirable qualities for risk assessment activities; the principles list the characteristics considered necessary to achieve the vision. The principles also provide a checklist to test resultant risk assessment activities against. This document is still under development as Enbridge continues to further its work on asset management and as such is not available for publication at this time.

e) Enbridge purchased RivaCP from Riva Modelling for the purpose of Asset Investment Planning. The tool captures and documents the business cases for both asset-based and needs-based projects. It aligns projects with departmental objectives, taking risk and other factors into account to determine the priority of a project. RivaCP allows visualization of both the short-term and long-range impacts of strategic decisions in real time with powerful, “What if” analysis. RivaCP serves as a repository for all projects that are currently being identified, prioritized, optimized and evaluated based on their overall Risk factor and their Value proposition to the entire organization.

Witness: T. MacLean

BOMA INTERROGATORY #13

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1

(a) Please provide a graph illustrating the Henry Hub price from January 1, 2015 to the present.

(b) Please extend Figure 8 to June 15, 2014. BOMA's understanding is that WCSB production and reserves increased in 2014 over 2013.

(c) Please indicate the amount of market-based storage EGD has contracted for in each of 2013, 2014 and 2015, relative to the amount of its own storage. Did EGD purchase the storage from Union, or Union and other suppliers; in what proportions; at what prices (approximate or range is sufficient)?

(d) Please provide the change in contracted interruptible service capacity, by rate class, for IT service in the years 2014, 2015, 2016.

(e) Please provide a list of the transportation commitments EGD made on (i) TCPL; and (ii) Union, 2016 and 2017 open seasons, both for existing and new customers, including the amounts, receipt and delivery points, and copies of Precedent Agreements.

(f) Please explain fully the analysis summarized in Figure 11, at Page 24.

(g) Does EGD intend to contract for additional supplies at Niagara (Marcellus) over the next five years? If it does not plan to increase its Niagara sourced supply, please explain. What is the landed cost at Parkway (Consumers) or elsewhere at Parkway, if applicable, of the gas supply it has contracted to move through TCPL from Niagara compared to the landed cost at Parkway of gas it has purchased at Dawn or upstream of Dawn, or plans to purchase, for the 2016 gas year. Please identify any assumptions underlying the analysis at Dawn for the cost of gas: (i) from other US sources; (b) from WCSB; (c) from Utica shale via NEXUS, then from Dawn to Parkway.

(h) Please confirm that gas purchases EGD makes at Niagara would flow from Niagara/Chippewa to Kirkwall, then to Parkway, on TCPL/Union, or, through the TCPL domestic lines from Niagara to Parkway (EGD).

Witnesses: D. Small
A. Welburn

RESPONSE

On July 17, 2014 the Ontario Energy Board issued its Decision with Reasons pertaining to the 2014 to 2018 custom Incentive Regulation Plan of Enbridge Gas Distribution (EB-2012-0459). Included as a part of that decision were a number of reporting requirements that Enbridge had committed to provide. One of those reporting requirements (see pp. 80 and 81 of EB-2012-0459 Decision) was to provide a Gas Supply Memorandum which would include:

1) a summary of the current natural gas market situation;
2) the results of the design day demand forecast with a discussion of the underpinning assumptions;
3) an overview of the current gas supply portfolio;
4) the identification of near term portfolio decisions and a description of how Enbridge strategy for the specific portfolio decision conforms to the gas supply planning principles; and
5) a summary of major upstream pipeline regulatory filings and/or recent regulatory orders (e.g., RH-003-2011); physical infrastructure projects that will likely Impact Enbridge; and the implications associated with gas supply basins.

Enbridge has filed its 2014-2015 Gas Supply Plan Memorandum in the 2014 ESM application in order to satisfy its reporting requirement. For the most part, the contents of the 2014-2015 Gas Supply Plan Memorandum are not relevant to any of the relief sought in this Application. As seen at Exhibit A, Tab 3, Schedule 1, the relief sought in this application all relates to the clearance of the Deferral and Variance Accounts set out at Exhibit A, Tab 2, Schedule 1, Appendix A.

a) An update of Henry Hub pricing from January 1, 2015 to present has no bearing on the relief sought in this 2014 ESM application.

b) The graph provided in Figure 8 “Historical Canadian Natural Gas Production” was intended for informational purposes and an update to the graph would not have any bearing on the relief sought in this 2014 ESM application.

c) Enbridge contracts for approximately 20% of its total storage requirement from third parties at market based rates. Effective April 1, 2010 all of the Company’s contracted third party storage is at market based rates. The Company acquires its Market Based storage through an RFP process such that replacement contracts are

Witnesses: D. Small
A. Welburn

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.

Currently, as of April 1, 2015 the Company has 8 different storage contracts which include 4 separate contracts with Union Gas. Listed below are the average unit rates ($/GJ) payable for market based storage service obtained as part of the RFP process since April 1, 2011.

April 1, 2011	0.79
April 1, 2012	0.54
April 1, 2013	0.73
April 1, 2014	0.44
April 1, 2015	0.64

d) As per EB-2012-0459, Exhibit D3, Tab 3, Schedule 3, page 1, the forecasted curtailment volume for 2013 and for 2014 remained relatively unchanged. It wasn't until after the extremely cold winter of January 2014 to March 2014 that Enbridge began to receive requests from customers to migrate from Interruptible service to Firm service. Enbridge accommodated those requests when possible and reflected a reduction of curtailable volumes for purposes of meeting its 2015 Peak Day Forecast. This was discussed in the Company's pre-filed evidence in EB-2014-0276 at Exhibit D1, Tab 2, Schedule 1, pages 4 through 6. The Company is still in the process of developing its Peak Day requirements for 2016.

e) The material requested has no bearing on the relief sought in this 2014 ESM application. However, the Company has prepared the table below which shows the commitments made by Enbridge in the 2016 and 2017 Open Seasons issued by Union Gas and TransCanada.

Witnesses: D. Small
A. Welburn

Open Season	Transportation Provider	Receipt Point	Delivery Point	Contracted Volume (GJ/day)	Comments
2016	Union Gas	Dawn	Parkway	170,000	
2016	TransCanada	Parkway	Enbridge EDA	170,000	
2017	Union Gas	Dawn	Parkway	190,000	
2017	TransCanada	Parkway	Enbridge EDA	83,114	Includes 63,468 LH conversion
2017	TransCanada	Parkway	Enbridge CDA	87,952	Includes 34,377 LH conversion

f) Please see response to FRPO Interrogatory #19 (Exhibit I.D.EGDI.FRPO.19).

g) A discussion of Enbridge Gas Distribution's potential supply plan portfolio over the next five years has no bearing on the relief sought in the 2014 ESM application. The Company will present its 2016 gas supply plan in the 2016 rate adjustment proceeding, and questions about the landed cost of gas supply for 2016 may be relevant in that proceeding.

h) The purchases Enbridge will be making at Niagara will flow through the TCPL domestic line from Niagara to Parkway.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #14

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1, Page 3

What cost reductions were identified in the EB-2012-0459 evidence? How was ratepayer cost relief "built into baseline costs"? Were the costs referred to both capital and operating costs? Please explain fully, including the amount of cost reduction to the baseline and the activities that were removed, altered, or otherwise managed to produce those cost reductions.

RESPONSE

Cost reductions in the form of embedded productivity savings and excluded variable capital cost savings were removed from Enbridge Gas Distribution's starting budgets to provide up-front reductions in known areas of cost pressures. Although productivity initiatives had yet to be developed to deliver to the lowered capital and O&M levels, these embedded reductions served as guaranteed savings to ratepayers prior to any savings being realized. The cost reductions embedded in Enbridge's budgets within the EB-2012-0459 proceeding were discussed and accepted within the Board's Decision at pages 35 and 36 (capital) and 46 to 51 (O&M).

Tables 1 and 2 on page 4 of Exhibit D, Tab 2, Schedule 1 show the cost reductions from Enbridge's starting budgets, replicated here.

Table 1

Other O&M Amounts Approved						
	2014	**2015**	**2016**	**2017**	**2018**	**Total IR Term**
Proposed "Other" O&M	252.1	261.6	276.6	287.8	299.5	1,377.6
Less: Embedded Savings	(24.1)	(30.1)	(35.6)	(39.3)	(43.2)	(172.3)
Less: OEB Adjustment	-	(1.2)	(8.4)	(13.6)	(19.0)	(42.2)
Approved "Other" O&M	228.0	230.3	232.6	234.9	237.3	1,163.1

Witnesses: I. Macpherson
M. Suarez

Table 2

Capital Amounts Approved						
	2014	**2015**	**2016**	**2017**	**2018**	**Total IR Term**
Core Capital without Productivity	495.1	538.3	544.9	527.1	537.2	2,642.7
Less: Embedded Savings	(26.2)	(28.7)	(27.1)	(35.2)	(45.3)	(162.5)
Less: Variable Costs	(25.1)	(63.0)	(75.9)	(50.0)	(50.0)	(264.1)
Approved Core Capital Expenditures	443.8	446.6	441.9	441.9	441.9	2,216.1

“Less: Embedded Savings” in Tables 1 and 2 relate to reductions in specific areas with known cost pressures. Those areas of savings are detailed in Table 3 and 4 of the same exhibit, again replicated here:

Table 3

2014 Embedded O&M Savings	
	($M)
Merit increase	(1.2)
Employee Benefits	(2.1)
Incremental cost to service new customers	(1.5)
Incremental safety and integrity work	(8.9)
External contractor rate increases	(0.3)
Increased volume of locates-compliance with Bill 8	(2.6)
Capped FTEs	(2.8)
Bad Debt expenses	(4.7)
Total O&M Productivity Guarantee	(24.1)

Table 4

2014 Embedded Capital Savings	
	($M)
Customer Attachments	(25.9)
Departmental Labour	(0.3)
Total	(26.2)

"Less: Variable Costs" in Table 2 relates to uncertain capital costs that were dependent on outcomes from planned studies and other future activities. These capital costs were excluded from the budget so that the risk of the costs materializing would be borne by Enbridge, and not by ratepayers. The specific cost areas were detailed in Table 7 at page 19 of the same exhibit, and are replicated here for ease of reference:

Table 7

Variable Costs Excluded from Capital Budget ($M)	**2014**
Sombra Redundancy	2.00
MOP VERIFICATION	5.30
ILI AND ASSESSMENT PRGM	6.20
SVC REPL LT $2M	2.25
COMM IND LOW PRESSURE REG STN	1.53
Load Research Prgm	0.55
STORAGE OVERVIEW	0.28
MCC#1 Generator and Boiler	0.50
meter boxes	0.18
Misc Structures	0.05
Engine Compressor Analyzer Automation	0.05
Misc. Wells	0.05
Misc Field Lines	0.05
Misc. Meas and Reg	0.05
Roads	0.05
Crowland Plant Automation	0.02
SCADA Upgrade and Automation	0.02
BUS DEV & CUST STRATEGY	2.61
IT PROJ LT $2M	0.90
FAC/GENL PL OVERVIEW	2.50
	25.14

Witnesses: I. Macpherson
M. Suarez

BOMA INTERROGATORY #15

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1, Page 12

Please explain the decrease in FTE equivalent positions, between the number in the budget, and the number at the end of 2014. In which units or groups were these FTEs located? Please provide a detailed breakdown. Does EGD intend to fill these positions in 2015, 2016, 2017, or 2018, or does it intend to hold the 150 FTEs (or whatever the actual number is) vacant throughout the IRM period?

RESPONSE

There are two main reasons for the difference between budget and actual FTEs in 2014.

One reason is that Enbridge Gas Distribution typically carries a number of vacancies throughout the year as employee movement is ongoing. Although it is expected that most vacancies will be filled, new vacancies will occur with the natural movement of employees. The Company expects to manage vacancies during the IRM period.

The second reason is that Enbridge has focused on limiting new hires to those that are deemed necessary. An increased focus on recruitment has provided the Company with solid business plans for filling vacancies and adding positions, and the additional diligence surrounding this process has reduced requests for new positions.

Please see the breakdown of FTEs by functional area on page 2.

Witnesses: I. Macpherson
A. Patel
M. Suarez
S. Trozzi

2014 Headcount & FTE			
Department	**2014 Budget**	**2014 Actual**	**Variance**
Corporate	15	11	4
GD Human Resources & Facil	77	58	19
GD Law & IT	197	168	29
GD, Finance & Regulatory	138	121	17
GD, Gas Sup & Bus Development	47	49	(2)
GD, Market Dev & Customer Care	248	223	26
GD, Dist Planning & Work Mgmt	428	424	4
GD, Distribution Operations	819	738	81
GD, Engineering & Integrity	245	235	10
GD, Strategy & Integrated Serv	131	119	12
Total Departments less WAMS & GTA	2,345	2,147	199
WAMS Program	15	42	(27)
GD, Engineering & Integrity-GTA Project	17	49	(32)
Total EGD + WAMS + GTA	2,377	2,237	140

Witnesses: I. Macpherson
A. Patel
M. Suarez
S. Trozzi

BOMA INTERROGATORY #16

INTERROGATORY

Annual Productivity Report

Ref: Ibid

Please provide the calculation of the $8.5 million in savings and explain how the number for representative FTE salary and benefits amount was chosen. Please perform the same exercise for the budgeted impact of the FTE freeze in 2015 (relative to 2014) of $3.1 million. Do the $8.5 million amount and the $3.1 million amount take into account the new hires for Asset Management in 2015?

RESPONSE

The calculation of $8.5 million is the difference between the 2014 budget and 2014 actual Salaries and Wages of $9.3 million, less the calculated merit savings of $0.8 million (which is the difference between the actual increase of 2.5% on average and the 3% target reduction). It represents the total reduction in gross salaries and wages in 2014 resulting from the management of FTEs.

The $3.1 million relates to the productivity savings implicit in the 2014 budget ($2.8M O&M and $0.3M capital) from operating without an anticipated incremental number of FTEs. The reduction is expected to be sustained with each year of the approved IR budgets.

To date, the positions created in 2015 to support the Asset Management Plan have been funded through existing vacancies. However, in future, there is the potential that incremental positons may need to be created.

Witnesses: I. Macpherson
L. Stickles
M. Suarez
S. Trozzi

BOMA INTERROGATORY #17

INTERROGATORY

Annual Productivity Report

Ref: Ibid

Do the FTE numbers exclude contract workers or part-time workers, or any other form of worker, other than full-time employees or their equivalents? Please discuss fully. What did EGD spend (number and OM&A dollars) of contracted or "temporary" staff in 2015 and 2014?

RESPONSE

FTE numbers include full-time, part-time, seasonal and temporary workers. Contract workers would be included in the same category as temporary workers, unless they were hired by a third party-independent company and not on Enbridge Gas Distribution's payroll where they would not be captured in the FTE numbers.

In 2014, Enbridge Gas Distribution had 108 temporary employees; however they were all not employed for the entire year. For example, this number would include 51 summer students that were employed for 4 months. The approximate spend for these temporary employees was $4.4 million.

Results for 2015 will be presented within the 2015 Earnings Sharing Application.

Witnesses: I. Macpherson
M. Suarez
S. Trozzi

BOMA INTERROGATORY #18

INTERROGATORY

Annual Productivity Report

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

Please provide a detailed list of the savings of $28.7 million relative to the core capital approved budget (EB-2012-0459) $443.8 million. Please identify for each savings item, whether it was to be "embedded savings" or variable costs, and the degree to which it is sustainable. Please confirm that the underspend in the system integrity program of approximately $6.4 million was simply due to a fifty percent underspend of the gate/station budget. Why did the underspend occur? Please confirm that the portion of the underspend at Cookstown and Keel will be spent in 2016.

RESPONSE

The details are listed in the table on page 2. All items are capital cost reductions relative to the approved capital budget. They are not considered to be sustainable as 2015 capital savings will be measured relative to the portfolio of projects for 2015 that was set out in EB-2012-0459.

The $6.4 million (Item #5 on the next page) includes $4.5 million related to the Cookstown and Keele/Finch gate stations. The delays were and continue to be due to external factors such as land acquisition issues and waiting for other third parties (i.e., TTC) to complete their respective processes. Both these projects are included for consideration for the 2016 capital budget prioritization process, which is currently underway.

Witnesses: L. Au
T. Knight
I. Macpherson
M. Suarez

2014 Actual vs. Budget - Core Capital Savings

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
		Actual	Budget	Actual Over/(Under)	% tage	Commentary	Paragraph Reference in Ex B/T2/S4
Capitalized Labour and Overheads		**105.8**	**118.0**	**(12.2)**	**-10%**	Reduced FTEs vs. budget levels ($7.8M) and lower interest during construction due to project delays ($4.1M)	Par 7
	Allocated Overheads						
Direct Capital							
1	Relocation Mains	0.8	15.2	(14.4)	-95%	Higher 3rd Party recoveries	Par 6
2	Information Technology	20.0	29.3	(9.3)	-32%	Response to evolving business needs	Par 8
3	Storage	11.2	19.2	(8.0)	-42%	Delays in the Tecumseh new building construction	Par 9
4	Reinforcements	3.6	11.4	(7.8)	-68%	Delays due to external factors	Par 10
5	System Integrity and Reliability	125.9	132.3	(6.4)	-5%	Delays due to external factors	Par 11
6	Other	7.4	8.7	(1.3)	-15%	Response to evolving business needs	
7	Facilities	29.7	23.6	6.1	26%	Response to evolving business needs	Par 13
8	Customer Growth	115.8	91.2	24.6	27%	Cost pressures include customer mix, rising municpal fees, extreme weather and geographic challenges	Par 12
	Subtotal Direct Capital	**314.4**	**330.9**	**(16.5)**	**-5%**		
	Summary Total	**420.2**	**448.9**	**(28.7)**	**-6%**		

Witnesses: L. Au
T. Knight
I. Macpherson
M. Suarez

BOMA INTERROGATORY #19

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1, Page 14

What were the amount of the financial contributions from the one time and unsustainable actions resulting in avoided costs in 2014? Were these variable costs or embedded savings? Please list each measure.

RESPONSE

As described in the evidence referenced at Exhibit D, Tab 2, Schedule 1, page 14, paragraph 40:

> "Other actions considered to be prudent business decisions that were made to take advantage of specific opportunities to enable future cost savings (although not originally identified in the budget) were considered to be avoided costs, but not productivity actions. There were also one-time opportunities for savings that were pursued but were not considered repeatable or sustainable. Such actions enabled the Company to achieve deeper savings than what would have been the case with embedded productivity savings and incremental initiatives alone. All such actions were not considered to qualify as productivity examples, and as such lie outside the scope of this report yet contribute to the overall positive financial and performance results in 2014."

Set out below are some examples of the avoided costs and one-time savings that Enbridge achieved in 2014. None of the capital costs savings were items identified in EB-2012-0459 as variable capital costs, but some of the one-time savings from hiring delays in 2014 may be included within the embedded savings identified in EB-2012-0459.

Most of the avoided costs identified in 2014 were capital-related.

For those avoided costs that related to IT capital, the Company identified solutions that allowed it to enhance or address shortcomings with certain computing systems, thereby providing efficiency, and saving the capital costs that would have been necessary to provide the enhancement required. Detailed estimates of capital cost savings were not carried out for the avoided enhancements.

Witnesses: I. Macpherson
M. Suarez

Another example of capital cost avoidance was in the use of mechanical tees. Enbridge Gas Distribution's engineering group evaluated the potential impact of switching to a welded fitting in accordance with the current policies, and determined that it was acceptable to continue using mechanical tees for polyethylene (plastic) services connected to NPS 1 and NPS 1.25 steel mains until current inventories were depleted or until the end 2016. The evaluation considered the performance of mechanical tees for the history of their use and found very few issues. The tees are no longer manufactured and Enbridge is moving towards an all-fused/welded system. The continued use of mechanical tees in this application reduces the need for additional welders, and results in capital cost avoidance of approximately $740 per service installation. Annual avoided capital costs are estimated at $237,000 based on approximately 320 installations per year.

Examples of actions which resulted in O&M savings were provided at Exhibit B, Tab 4, Schedule 2, page 2 as part of the explanation of O&M expense variance relative to the Board approved O&M expense. Hiring delays (staff lags) and staff secondments accounted for many of the one-time savings opportunities. Additional savings were enabled through deferred program costs.

Witnesses: I. Macpherson
M. Suarez

BOMA INTERROGATORY #20

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1, Page 19, Table 7

Please show which of the items in the table have materialized, and which did not. For those that did materialize, please confirm they were absorbed within the capital budget.

If not all initiatives were absorbed, indicate the increase to the capital budget from those items.

Please explain each of the items proposed in EB-2012-0459, or provide a reference to where those initiatives were described in EB-2012-0459 or in other proceedings

Please provide a breakdown of the table into capital and operating components.

When will automatic meter reading be available and deployed for natural gas? Please discuss.

RESPONSE

Please see the updated Table 7 on page 2 of this response, which shows which variable costs materialized in 2014.

As stated at paragraph 52 of the referenced exhibit:

> Most of the variable capital costs identified for 2014 in the Custom IR filing have been determined to not have materialized. Because of the uncertain nature of these variable cost elements, a number of projects were not adequately itemized or tracked and subsequent changes in scope made it challenging to determine how work items were ultimately captured in the budget or in actual spend. Those variable costs that did arise were mitigated or absorbed within the overall capital spending.

Witnesses: K. Lakatos-Hayward
I. Macpherson
M. Suarez

Excluded variable capital costs were addressed as part of the EB-2012-0459 proceeding at the following references:

- Exhibit A2, Tab 1, Schedule 1
- Exhibit B2, Tab 1, Schedule 1
- Exhibit I.B18.EGDI.STAFF.55
- Exhibit I.B19.EGDI.SEC.93; and
- Exhibit J1.6

All amounts in Table 7 are excluded capital amounts.

Variable Costs Excluded from Capital Budget ($M)	**2014**	**2014 Update**
Sombra Redundancy	2.00	did not materialize
MOP VERIFICATION	5.30	re-assessed & absorbed
ILI AND ASSESSMENT PRGM	6.20	re-assessed & absorbed
SVC REPL LT $2M	2.25	re-assessed & absorbed
COMM IND LOW PRESSURE REG STN	1.53	not tracked
Load Research Prgm	0.55	did not materialize
STORAGE OVERVIEW	0.28	did not materialize
MCC#1 Generator and Boiler	0.50	deferred
meter boxes	0.18	not tracked
Misc Structures	0.05	did not materialize
Engine Compressor Analyzer Automation	0.05	half the amount materialized; was absorbed
Misc. Wells	0.05	did not materialize
Misc Field Lines	0.05	did not materialize
Misc. Meas and Reg	0.05	did not materialize
Roads	0.05	absorbed
Crowland Plant Automation	0.02	deferred
SCADA Upgrade and Automation	0.02	absorbed
BUS DEV & CUST STRATEGY	2.61	saved 0.5k; the balance did not materialize
IT PROJ LT $2M	0.90	cancelled
FAC/GENL PL OVERVIEW	2.50	did not materialize
	25.14	

Witnesses: K. Lakatos-Hayward
I. Macpherson
M. Suarez

Automatic Meter Reading (AMR)

In its Custom IR application, Enbridge Gas Distribution did not include a plan for Automatic Meter Reading ("AMR"). Since the application, however, a number of factors have changed which has renewed the Company's interest in AMR[1].

Most importantly, the Government of Ontario has announced a proposal to introduce cap-and-trade legislation as a mechanism to reach the Province's greenhouse gas emission targets, and is likely to include natural gas as a covered sector commencing in 2017. While details have not been finalized, it appears that the utility will be responsible for purchasing allowances on behalf of all customers[2], based on consumption at the customer meter. This requirement underpins the importance of more timely meter reads than the current meter reading every two months. As Ontario moves into a carbon-constrained environment, equally important will be use of consumption data from AMR to support behavioral DSM opportunities and more accurate peak hourly data to support local integrated resource planning.

Additionally, as part of the Company's efforts to review opportunities to drive productivity, a business case for AMR has been drafted. While the annual O&M savings are compelling (greater than $12M per year once fully deployed), the capital cost to install AMR for all of the Company's 2 million customers would amount to approximately $170M and this amount has not been included in Enbridge Gas Distribution's core capital investment plan for the Custom IR term.

In summary, while the Company does not currently have within the current IR term a plan for AMR, for the reasons stated above the Company would welcome an opportunity to work with the Ontario Energy Board and intervenors to advance a stand-alone application for AMR.

[1] The Company first proposed AMR in EB-2006-0034 Exhibit B1 Tab 7 Schedule 1 but withdrew the request in the Settlement Agreement.

[2] Excluding large final emitters.

Witnesses: K. Lakatos-Hayward
I. Macpherson
M. Suarez

BOMA INTERROGATORY #21

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1, Page 9

(a) Please explain why "benefits" costs continue to increase six percent per year.

(b) Please breakdown the benefits into detailed components and show the increase in costs for each component and the calculation which produces the six percent overall rate.

(c) Please estimate the likely reduction in the six percent increase in 2015 and 2016 which will result from the benefits policy changes shown at paragraph 22. Are these reductions sustainable beyond 2016?

(d) Please explain what the annual increase in benefit costs would be if EGD employees were to contribute a share (25%) to their pension contributions.

RESPONSE

a) Rising benefit costs are due to a combination of factors, such as increased utilization by employees, long term disability cost increases, inflationary increases in prescriptions and dental services, and the introduction of new drugs from manufacturers that carry a high cost.

b) The six percent increase is an estimate that was set in accordance with information obtained from the Company's benefit consultants. The estimate would take into account past experience, the increase in employee salaries, anticipated increase in employee utilization, and apply predicted trends and inflation.

c) The Company remains committed to preventing the uncontrolled escalation of benefit costs, and therefore instituted a number of changes to the benefits program effective January 2015. One of the changes Enbridge Gas Distribution instituted is the prior-authorization on some of the new high cost drugs to ensure the Company

Witnesses: I. Macpherson
A. Patel
M. Suarez
S. Trozzi

only pays for these drugs when they meet the clinical indications of them and they are administered in accordance with Health Canada approvals and guidelines. A $1 million life time maximum also ensures that Enbridge does not face unlimited liability for these drugs. Other changes include benefit credits based on salaries at January 1 with no further increases throughout the year, mandatory generic drug substitutions, dispensing fee caps, and a maximum on vaccinations. These changes are expected to assist in keeping benefit costs from escalating further and are expected to sustain a reduction in future years. Within its 2015 Productivity Report, the Company will be able to provide information about the magnitude of benefit cost reductions for 2015.

d) If employees were to contribute 25% to the pension plan, the estimated reduction in Enbridge Gas Distribution’s pension costs would be roughly $5.6 million.

This estimate is provided for information purposes only. Enbridge will not be introducing employee contributions as it would negatively impact our total compensation philosophy of positioning ourselves at the 50th percentile of the market in which Enbridge competes for talent. In order to maintain our market competitiveness and Company philosophy, other components of the total compensation package would need to increase resulting in no change to Enbridge’s overall costs. Additionally, a change such as this would need to be negotiated through collective bargaining with the unionized workforce.

Witnesses: I. Macpherson
A. Patel
M. Suarez
S. Trozzi

BOMA INTERROGATORY #22

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1

(a) What accounted for the locates volume increase of thirteen percent in 2014? Was this an anomaly? What is the experience to date, year over year, for January 1-June 30 for 2013, 2014, and 2015?

(b) What further progress, if any, on damage prevention ratios is EGD predicting for 2015, 2016, 2017, and 2018? Why?

RESPONSE

a) The locates volume increase of 13% in 2014 as compared to 2013 is primarily attributable to implementation of the Ontario Underground Infrastructure Notification System Act and regulations. Locate volumes increase year over year for January 1 to June 30 2013 to 2014 was approximately 10% and for the same period 2014 to 2015 approximately 5%.

b) From 2010 to 2014, excavator damages decreased and locate requests grew substantially. Provided this trending continues, Enbridge Gas Distribution can anticipate further positive progress on the damage prevention ratio.

Witnesses: P. Jurgeneit
I. Macpherson
M. Suarez
T. Tuck

BOMA INTERROGATORY #23

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 1

Please explain how EGD suddenly becomes an uncompetitive employer if average merit increases are held to two percent, rather than three percent, given the state of the economy, interest rates, CPI forecasts, etc. Do the merit pay increases take into account the extent to which the employee is in a category, the demand for which is especially intense?

RESPONSE

Enbridge Gas Distribution participates in annual compensation surveys to ensure that its compensation programs remain competitive within the market where the Company competes for talent. These surveys indicated a 3% merit increase would maintain competitiveness and would be consistent with the Company philosophy of maintaining its compensations programs at the 50th percentile of the market. These surveys provide data that Enbridge Gas Distribution uses to ensure the Company's overall compensation program is designed to maintain its position appropriately in the market within all employee categories. In calculating the annual merit increase, careful consideration is given to the trade-off between affordability and the extent of investment needed to retain/engage top performers. Enbridge Gas Distribution's salary range movement aligns with the market and offsets inflation. The compensation program encourages pay differentiation through evaluation of merit based on performance. The Company continues to invest in top talent – based on both performance and critical roles. If a specific employee category requires additional merit dollars, this is managed within the merit budget allocation. Overall merit increases are otherwise based on employee performance.

Witnesses: I. Macpherson
M. Suarez

BOMA INTERROGATORY #24

INTERROGATORY

Annual Productivity Report

Ref: Exhibit D, Tab 2, Schedule 11

What savings would be produced by eliminating all discretionary customer attachment projects in the winter? Define a residential replacement customer and show how it differs from a residential conversion customer. What is the current dollar value (total) of the winter premium for 2014-2015. Over what months is it calculated, in each EGD region?

RESPONSE

Customer attachment in the winter months is not a discretionary function. In southern Ontario, specifically within Enbridge Gas Distribution Inc.'s franchise area, homebuilders and construction companies construct in all months including the winter. Enbridge Gas Distribution has seen an increase in service requests during the winter months in the past several years.

A residential replacement customer or a residential conversion customer is considered the same customer type by Enbridge Gas Distribution. By definition, it is a customer converting their existing home to natural gas from another primary fuel source such as electricity, propane, or oil.

Enbridge Gas Distribution Inc. spent approximately $7.1million on winter premiums in 2014 and $6.9 million on winter premiums in 2015 for customer related construction during the months of January to March (inclusive). Winter premiums range from 30% to 50% depending on geographic region and construction type.

Witnesses: P. Green
I. Macpherson
F. Smith
M. Suarez

CCC INTERROGATORY #6

INTERROGATORY

Ex. D/T1/S3/p. 1

EGD has indicated that the WAMS project has cost overruns and that there is uncertainty with respect to the final project cost. When will EGD be seeking final approval of the costs associated with the WAMS project?

RESPONSE

Enbridge anticipates that actual WAMS project costs will be included within 2016 actual results, and in particular the derivation of 2016 rate base (which is relevant for earnings sharing purposes, but not for ratemaking purposes). The review and approval of actual 2016 results, from an earnings sharing perspective, will occur as part of Enbridge's 2016 earnings sharing and deferral clearance application, which is expected to occur in the spring of 2017. From a rate setting perspective, Enbridge anticipates seeking approval to recover the revenue requirement associated with actual WAMS project costs (based on the depreciated net book value) commencing in its 2019 rate application, after the completion of its current custom incentive regulation term.

Witnesses: W. Akkermans
B. Misra
R. Small

CCC INTERROGATORY #7

INTERROGATORY

Ex. D/T1/S2

EGD has indicated that the GTA Project has cost overruns. When will EGD be seeking final approval of the costs associated with the GTA Project?

RESPONSE

Enbridge will seek approval to recover the revenue requirement associated with actual GTA project costs (based on the depreciated value) commencing in its 2019 rate application. Enbridge anticipates that actual GTA project costs will be included within 2015 actual results, and in particular the derivation of 2015 rate base (which is relevant for earnings sharing purposes, but not for ratemaking purposes). As part of Enbridge's 2015 earnings sharing and deferral clearance application, the actual 2015 GTA project costs incurred will be reviewed, which includes the majority of actual GTA project costs, but excludes some restoration and closeout costs, and costs related to the Buttonville and Jonesville stations, which will be placed into service beyond 2015. Those additional costs will be reviewed as part of the earnings sharing and deferral clearance applications for those subsequent years.

Witnesses: S. Dodd
O. Schneider
R. Small

CCC INTERROGATORY #8

INTERROGATORY

Ex. D/T2/S1/p. 1

What relief, if any is EGD seeking from the Board through this Application regarding its Annual Productivity Report?

RESPONSE

The Company is not seeking any relief through this Application with respect to its Annual Productivity Report. In the EB-2012-0459 proceeding, Enbridge agreed to provide the Annual Productivity Report as part of the Company's annual reporting requirements to the Board. The Board accepted and required that reporting (see page 79 of the Decision). The objective of the Annual Productivity Report is to provide visibility to the productivity improvements pursued which allow the Company to sustainably operate within its budget over the Custom IR term.

Witnesses: I. Macpherson
M. Suarez

CCC INTERROGATORY #9

INTERROGATORY

Ex. D/T4/S1

What relief, if any is EGD seeking through this Application with respect to it 2014-2015 Gas Supply Memorandum or gas supply plans?

RESPONSE

The Company is not seeking any relief through this Application with respect to its 2014-2015 Gas Supply Memorandum. In the EB-2012-0459 proceeding, Enbridge agreed to provide an annual Gas Supply Memorandum as part of its annual stakeholder meeting. Enbridge did so for its 2015 stakeholder meeting. Enbridge is required to file the materials from its annual stakeholder meeting in its next ESM proceeding, and that is why the Gas Supply Memorandum is filed in this Application.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #11

INTERROGATORY

Ref: Exhibit D, Tab 1, Schedule 6, Page 1

Please provide updated costs for the Asset Management Study?

a) To what budget centre are these costs assigned?
b) Has Enbridge not already filed a Distribution Integrity Management Program with the TSSA?
c) In what substantive ways are the two approaches different?
d) How will Enbridge reconcile its Asset Management plan with the submissions to the TSSA?

RESPONSE

a) Please refer to BOMA Interrogatory #12 (Exhibit I.D.EGDI.BOMA.12).

b) Enbridge does maintain a Distribution System Integrity Management Program, in compliance with the requirements of the Oil and Gas Pipeline Systems Code Adoption Document (FS-196-12) and CSA Z-662. Please refer to Undertaking J5.11 from EB-2012-0459 for further detail. Enbridge has not filed the Distribution Integrity Management program with the TSSA.

c) Integrity Management pursues the engineering science associated with the health and condition of the assets (i.e., running in-line inspections to determine asset condition) to determine asset life and the risks associated with the assets, and Asset Management balances the operational, financial and risk elements of managing the assets, according to the determined risks and asset life, to ensure that the capital spend appropriately reduces risk across the assets.

d) The Asset Management plan will identify the collection of risks in an optimized portfolio. The requirement with the TSSA is to show that Enbridge is managing risk appropriately through the operation of a safe and reliable distribution system.

Witness: T. Maclean

FRPO INTERROGATORY #12

INTERROGATORY

Ref: Exhibit D, Tab 2, Schedule 1, Page 8

Preamble: Table 3 refers to an O&M Performance guarantee

Please clarify the meaning of “guarantee” as it pertains to these items.

RESPONSE

As explained in paragraph 18 on page 7 of the referenced exhibit, which explains the information contained in Table 3.

> Embedded productivity savings represent the anticipated cost pressures that were eliminated or held flat within the capital and O&M budgets … as guaranteed savings which serve as a productivity assurance to ratepayers.

Although the Company had not identified the manner in which savings would be achieved nor was it certain that it could deliver on the savings targets, the embedded cost reduction served as a ratepayer guarantee through lower up-front costs approved by the Board within rates. This was a powerful incentive for the Company to find savings in other areas so as to operate within the budgets approved.

Witnesses: I. Macperson
M. Suarez

FRPO INTERROGATORY #13

INTERROGATORY

Ref: Exhibit D, Tab 2, Schedule 1, Page 10

Preamble: “In fact, volumes increased by about 13% in 2014, directly contributing to a proportional increase in costs.”

Does this sentence meant that costs went up 13% and there was zero productivity improvement?

RESPONSE

Consistent with Exhibit D, Tab 2, Schedule 1, locate volumes increased by about 13% in 2014. The Alternative Locate Agreement initiative improved locate efficiency with resultant incremental savings of $0.4 million in 2014. However, the costs associated with locate efficiencies could not offset higher costs from the increase in locate volumes in 2014.

Witnesses: P. Jurgeneit
I. Macpherson
M. Suarez
T. Tuck

FRPO INTERROGATORY #14

INTERROGATORY

Ref: Exhibit D, Tab 2, Schedule 1, Page 11

What is the rate impact of the budget guarantee of $4.7M related to bad debt when $2.1M is achieved?

RESPONSE

2014 Rates reflect the full $4.7 million reduction in the budget related to bad debt savings. There is no additional rate impact to customers stemming from the Company's savings shortfall in that area.

Witnesses: I. Macperson
M. Suarez

FRPO INTERROGATORY #15

INTERROGATORY

Ref: Exhibit D, Tab 2, Schedule 1, Page 20

Are the capital reductions cited in Table 8 a result of the difference in budgeted cost versus actual cost or deferral of all or a portion of a capital project to a future period?

a) If the answer is a combination, please provide the breakdown between the two.

RESPONSE

a) Please see the response to BOMA Interrogatory #18 at Exhibit I.D.EGDI.BOMA.18.

Witnesses: L. Au
T. Knight
I. Macperson
M. Suarez

FRPO INTERROGATORY #16

INTERROGATORY

Ref: Exhibit D, Tab 3, Schedule 1, Page 13

What is EGD's expected timing for Phase 2 of the Dawn Access consultation?

RESPONSE

Pursuant to its commitment in the Dawn Access Settlement Agreement, the Company has recently contacted stakeholder representatives for unbundled customers and initiated its commitment for continued consultation with respect to unbundled Dawn transport service or unbundled service changes. If new unbundled transport service(s) or unbundled transport service changes can be agreed upon, the Company will review these proposed service or service changes with affected parties and seek Board approval at an appropriate time.

Witness: K. Culbert

FRPO INTERROGATORY #17

INTERROGATORY

Ref: Exhibit D, Tab 3, Schedule 1, Page 58

Please provide an update on New Community Expansion projects.

RESPONSE

Enbridge Gas Distribution is currently in the process of preparing detailed cost and revenue estimates for several potential community expansion projects. This work is being undertaken by the Company with a view to bringing one or more Leave to Construct applications before the Ontario Energy Board between now and the end of the year with respect to the extension of gas distribution services to these communities.

Witnesses: K. Culbert
S. McGill

FRPO INTERROGATORY #18

INTERROGATORY

Ref: Exhibit D, Tab 3, Schedule 1, Page 108

Please clarify how Vector contributes to the in-franchise delivery to EGD (i.e., how does it get to the franchise)?

RESPONSE

Gas transported via the Vector Pipeline is delivered to Union Dawn. This gas is injected into storage in the summer and used to supplement storage withdrawals and other Dawn deliveries in the winter to help meet demand in the CDA and EDA using a combination of Union M12 and/or TCPL short haul transportation capacity.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #19

INTERROGATORY

Ref: Exhibit D, Tab 3, Schedule 1, Page 109

Please provide the detailed analysis to support the need to for an additional 16 Bcf of storage.

RESPONSE

The Company does not have a complete and detailed analysis at this point in time. As discussed at the Company's April 1, 2015 Stakeholder Presentation, the Company intends to perform a detailed review of the need for incremental storage for 2016 and beyond with the support of an external consultant, at some time in the future.

Witnesses: J. Leblanc
D. Small

FRPO INTERROGATORY #20

INTERROGATORY

Ref: Exhibit D, Tab 3, Schedule 1, Page 109

Please discuss why the alternative of purchasing at Dawn on an as-needed basis to maintain storage targets throughout is not superior to additional storage from a risk management perspective?

RESPONSE

Please see response to FRPO Interrogatory #19 found at Exhibit I.D.EGDI.FRPO.19.

Witnesses: J. Leblanc
D. Small

FRPO INTERROGATORY #21

INTERROGATORY

Ref: Exhibit D, Tab 3, Schedule 1, Page 109

Please provide Enbridge's analysis similar to Union's Incremental Transportation Contract Analysis that supports this commitment.

a) Please clarify any other factors that contribute to the decision making.

b) Please include in the analysis the opportunity to contract for supply at Iroquois as part of the portfolio.

RESPONSE

a) and b) See response to FRPO Interrogatory #19 found at Exhibit I.D.EGDI.FRPO.19.

Witnesses: J. Leblanc
D. Small

FRPO INTERROGATORY #22

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 18

Please provide the expected level of reduction of FT when Kings North goes into service?

RESPONSE

TransCanada offered new transportation capacity, effective as of the anticipated November 1, 2015 in-service date for the King's North Connection Pipeline Project , under a New Capacity Open Season (the "2015 NCOS"). The Company did not bid for any new capacity in the 2015 NCOS and as a result will not be making any changes to its FT capacity when the project goes into service.

Note that the Company has made bids under the 2016 NCOS and 2017 NCOS for capacity starting on November 1, 2016 and November 1, 2017. This is discussed at pages 21 and 22 of the noted Exhibit D, Tab 4, Schedule 1.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #23

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 18

What is EGD understanding of the timing of that transition?

RESPONSE

The interrogatory is unclear as to what specific transition is being referred to in the provided reference. For the purpose of providing a response, the Company is assuming that the transition being referred to in this interrogatory is related to the King's North Connection Pipeline Project as this was the subject matter of the previous interrogatory.

TransCanada has indicated that construction of this project will take 9 to 12 months after National Energy Board approval and compliance with any pre-construction conditions of the Order[1]. The National Energy Board released its Letter Decision on June 2, 2015 approving the project subject to conditions including a pre-construction condition that a construction schedule be filed at least 14 days prior to commencing construction[2]. The Company is not aware of this condition being satisfied as of the date of this response and as a result estimates the earliest that the project would be completed is April 2016.

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[1] GHW-001-2014 TransCanada PipeLines Limited King's North Connection Pipeline Project Additional Written Evidence dated December 22, 2014, pages 2-3.

[2] National Energy Board Letter Decision re: Hearing Order GHW-001-2014 TransCanada PipeLines Limited (TransCanada) Application for the King's North Connection Pipeline Project (Project) Decision and Order with Reasons to Follow dated June 2, 2015, condition number 7.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #24

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 18

Given the 2015 change in methodology of UDC management and the anticipated summer of 2016 transition of Long Haul FT to SH with Kings North in service, please describe in detail, the methodologies EGD intends to use to mitigate ratepayer risk for UDC on the Long Haul transport (please ensure specificity in the company's response beyond a statement of best efforts).

RESPONSE

The Company is still developing its 2016 gas supply plan, which will be presented in the 2016 Rate Adjustment proceeding. It is premature to address questions about expected UDC or any related UDC management plan for 2016 at this time.

The Supplementary Settlement Proposal in EB-2014-0276 dealt with the Settlement of Upstream Capacity Management Issue. Within that Settlement Agreement, there is a section entitled "Applicability to Future Years" (Exhibit N1, Tab 1, Schedule 2, page 9 of 9). The Settlement Agreement states that should there be any forecasted UDC beyond 2015, then the Company will develop a UDC Management Plan and will provide such plan as a part of its gas supply plan that is normally filed in connection with the annual rate application process. Therefore, should there be any forecast UDC in 2016 the Company will include a UDC Management Plan as part of its 2016 rate application.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #25

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 19

Please provide a more specific description of the assumption described including rights, obligations and terms (i.e., contracting terms not the name of the counterparty).

RESPONSE

The interrogatory is unclear as to what specific assumption is being referred to in the provided reference. For the purpose of providing a response, the Company is assuming that the assumption being referred to in this interrogatory is related to the acquisition of 200,000 GJ/day of natural gas supply at the Niagara interconnect on the TransCanada Canadian Mainline System since the subsequent interrogatory includes the same reference and infers a supply point.

The Company is in the process of negotiating natural gas supply contracts with four counterparties for the 200,000 GJ/d of natural gas supply that will be received at either the Niagara and/or Chippawa receipt points. All of the contracts are expected to have a start date of January 1, 2016 with a 22 month term that expires on October 31, 2017. The Company has attempted to negotiate a combination of seasonal and annual supply contracts but, due to the lack of liquidity at the Niagara and Chippawa interconnects at this time, the majority of suppliers require the supply contracts to be on an annual basis. Pricing for all of the contracts will be based on Dawn less a negotiated amount once again due to the lack of liquidity at the Niagara and Chippawa interconnects.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #26

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 19

How does EGD intend to manage that supply point during the summer periods of lower consumption?

RESPONSE

The interrogatory is unclear as to what specific supply point is being referred to in the provided reference. For the purpose of providing a response, the Company is assuming that the supply point being referred to in this interrogatory is related to the acquisition of 200,000 GJ/day of natural gas supply at the Niagara interconnect on the TransCanada Canadian Mainline System.

The Company is in the process of developing its 2016 gas supply plan. Among other things, the 2016 gas supply plan will address how the 200,000 GJ/d of natural gas supply at the Niagara/Chippawa interconnect will be managed. The Company will present its 2016 gas supply plan in its 2016 rate application.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #27

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 20

Please provide the annualized cost of storage space/GJ for the period of 2012 to 2015 segregated by:

a) EGD Tecumseh and other owned asset storage
b) Third party storage
c) To the extent that there are non-standard deliverability terms, please differentiate the respective storage unit costs.

RESPONSE

a) For the purposes of designing rates the Company allocates total forecasted Tecumseh O&M. Depreciation, Taxes and Utility Return on Rate Base between Transmission and Storage Service. A detailed breakdown of this classification of cost of service can be found at Exhibit G2, Tab 7, Schedule 3, of the applicable Test Year filing. The storage costs are broken down further as either Deliverability or Seasonal Space and include a reduction for forecasted revenue from Transactional Services. A detailed breakdown of this classification of cost of service can be found at Exhibit G2, Tab 6, Schedule 2, of the applicable Test Year filing. Copies of the relevant schedules for the 2013, 2014 and 2015 are attached to this response. A similar allocation between Deliverability and Seasonal Space is used for purposes of allocating Market Based Storage costs. Based upon the forecasted costs for 2013 to 2015, the per unit value of Tecumseh storage service is approximately $0.15 to $0.17/GJ.

b) In response to BOMA Interrogatory #13 (Exhibit I.D.EGDI.BOMA.13) the Company provided the per unit value for market based storage purchased by the Company as a part of its storage RFP process for each of the last five years.

c) Bids that are received by the Company as a part of the Annual Storage RFP process will be for different amounts of total storage, varying length of term and for different injection and withdrawal deliverability terms however, the bids price is a solitary price. In other words, the unit rates of bids received are not broken out by each element or characteristic of the storage service being offered. The Company does not wish to assign its own value for these different services to respond to this question, because that might influence the bidding process for future Storage RFPs.

Witnesses: D. Small
A. Welburn

TECUMSEH GAS
CLASSIFICATION OF COST OF SERVICE
2013 TEST YEAR
($000)

Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Storage Space	Col. 1 Transmission & Compression Total	Col. 2 Alloc'tn Ann	Col. 3 Dly	Col. 4 Annual Demand	Col. 5 Daily Demand	Col. 6 Commodity	Col. 7 Pool Storage Storage Total	Col. 8 Union Transfer	Col. 9 Net Tecumseh	Col. 10 Alloc'tn Ann	Col. 11 Dly	Col. 12 Annual Demand	Col. 13 Daily Demand	Col. 14 Commodity
	RATE BASE RETURN AMOUNT																			
1.1	Utility Return	45%	55%	19,376.3	8,719.3	10,656.9	8,719.3	35%	65%	3,051.8	5,667.6		10,656.9	0.0	10,656.9	35%	65%	3,729.9	6,927.0	
1.	Total Return			19,376.3	8,719.3	10,656.9	8,719.3			3,051.8	5,667.6		10,656.9	0.0	10,656.9			3,729.9	6,927.0	
	EXPENSES - OPERATION																			
2.1.1	Labour	75%	25%	1,358.3	1,018.7	339.6	1,018.7	35%	65%	356.5	662.2		339.6	19.9	319.7	35%	65%	111.9	207.8	
2.1.2	Supplies & Other	90%	10%	565.5	509.0	56.6	509.0	20%	30%	101.8	152.7	254.5	56.6	3.3	53.3	30%	45%	16.0	24.0	13.3
2.1.3	Hydro	100%	0%	358.0	358.0		358.0	20%	30%	71.6	107.4	179.0				0%	0%			
2.1.4	Lease Rentals	0%	100%	1,576.0		1,576.0		35%	65%				1,576.0		1,576.0	35%	65%	551.6	1,024.4	
2.1.5	Surface Rentals	0%	100%	338.0		338.0		35%	65%				338.0	19.8	318.2	35%	65%	111.4	206.9	
2.1.6	Provision for LUF	87%	13%	3,751.8	3,264.1	487.7	3,264.1	0%	0%			3,264.1	487.7	0.0	487.7	0%	0%			487.7
2.1	Subtotal			7,947.7	5,149.8	2,797.9	5,149.8			529.9	922.3	3,697.6	2,797.9	42.9	2,755.0			790.9	1,463.1	501.0
	MAINTENANCE																			
2.2.1	Company	80%	20%	1,470.6	1,176.5	294.1	1,176.5	20%	30%	235.3	353.0	588.2	294.1	17.2	276.9	30%	45%	83.1	124.6	69.2
2.2.2	Contractor	55%	45%	1,515.5	833.5	682.0	833.5	20%	30%	166.7	250.1	416.7	682.0	39.9	642.1	30%	45%	192.6	289.0	160.5
2.2	Subtotal			2,986.2	2,010.0	976.1	2,010.0			402.0	603.1	1,004.9	976.1	57.1	919.0			275.7	413.6	229.7
	ADMINISTRATIVE & GENERAL																			
2.3.1	General Office	75%	25%	2,924.9	2,193.7	731.2	2,193.7	35%	65%	767.8	1,425.9		731.2	42.7	688.5	35%	65%	241.0	447.5	
2.3.2	Service Fees	75%	25%	2,650.1	1,987.6	662.5	1,987.6	35%	65%	695.7	1,291.9		662.5	38.7	623.8	35%	65%	218.3	405.5	
2.3.3	Overhead Capitalized	75%	25%	(908.9)	(681.7)	(227.2)	(681.7)	35%	65%	(238.6)	(443.1)		(227.2)	0.0	(227.2)	35%	65%	(79.5)	(147.7)	
2.3	Subtotal			4,666.1	3,499.6	1,166.5	3,499.6			1,224.9	2,274.7		1,166.5	81.5	1,085.0			379.8	705.3	0.0
	DEPRECIATION AND AMORTIZATION																			
2.4.1	Depreciation	56%	44%	5,502.4	3,086.3	2,416.1	3,086.3	35%	65%	1,080.2	2,006.1		2,416.1	138.4	2,277.7	35%	65%	797.2	1,480.5	0.0
2.4.2	Amortization	0%	100%	497.9		497.9		35%	65%				497.9	0.0	497.9	35%	65%	174.3	323.6	0.0
2.4	Subtotal			6,000.3	3,086.3	2,914.0	3,086.3			1,080.2	2,006.1		2,914.0	138.4	2,775.6			971.5	1,804.1	
	TAXES - OTHER THAN INCOME																			
2.5.1	Municipal	80%	20%	2,261.1	1,808.9	452.2	1,808.9	35%	65%	633.1	1,175.8		452.2	26.4	425.8	35%	65%	149.0	276.7	
2.5.2	Capital Rate Base Ratio	45%	55%	0.0	0.0	0.0	0.0	35%	65%				0.0			35%	65%			
2.5	Subtotal			2,261.1	1,808.9	452.2	1,808.9			633.1	1,175.8		452.2	26.4	425.8			149.0	276.7	
2.	**TOTAL EXPENSES**			23,861.4	15,554.6	8,306.7	15,554.6			3,870.1	6,982.0	4,702.5	8,306.7	346.3	7,960.4			2,566.9	4,662.8	730.7
3.	**REVENUE REQUIREMENT**			43,237.6	24,273.9	18,963.6	24,273.9			6,921.9	12,649.6	4,702.5	18,963.6	346.3	18,617.3			6,296.8	11,589.8	730.7
4.1	**GROSS REVENUE REQUIREMENT (incl. fuel)**			43,237.6	24,273.9	18,963.6	24,273.9			6,921.9	12,649.6	4,702.5	18,963.6	346.3	18,617.3			6,296.8	11,589.8	730.7
4.2	**GROSS REVENUE REQUIREMENT (excl. fuel)**			43,237.6	24,273.9	18,963.6	24,273.9			6,921.9	12,649.6	4,702.5	18,963.6	346.3	18,617.3			6,296.8	11,589.8	730.7
3.1.1	Less: UNION GAS									404.6	779.9	274.9						0.0	0.0	0.0
3.1.2	Less: CENTRA GAS									70.8	77.9	48.1						68.4	76.1	7.9
3.1.3	Less: ST. LAWRENCE									0.0	0.0	0.0						0.0	0.0	0.0
3.1	**Net: CONSUMERS GAS**									6,446.5	11,791.8	4,379.5						6,228.4	11,513.7	722.8

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	6,446.5	6,446.5	0.0	6,446.5	0.0	0.0
1.2	Daily Demand	11,791.8	11,791.8	11,791.8	0.0	0.0	0.0
1.3	In/out	4,379.5	4,379.5	0.0	4,379.5	0.0	0.0
1.4	Fuel	3,606.0	3,606.0	0.0	3,606.0	0.0	0.0
1.5	Transactional Services Revenues	(1,684.2)	(1,684.2)	(1,010.5)	(673.7)	0.0	0.0
1.	Total Transmission	24,539.6	24,539.6	10,781.3	13,758.3	0.0	0.0
	STORAGE						
2.1	Annual Demand	6,228.4	6,228.4	0.0	6,228.4	0.0	0.0
2.2	Daily Demand	11,513.7	11,513.7	11,513.7	0.0	0.0	0.0
2.3	In/out	722.8	722.8	0.0	722.8	0.0	0.0
2.4	Transactional Services Revenues	(1,315.8)	(1,315.8)	(789.5)	(526.3)	0.0	0.0
2.	Total Storage	17,149.1	17,149.1	10,724.2	6,424.9	0.0	0.0
3.	Total Tecumseh	41,688.7	41,688.7	21,505.5	20,183.2	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		9,119.3	0.0	9,119.3	0.0	0.0
4.2	Peak		11,145.8	11,145.8	0.0	0.0	0.0
4.3	Injection		125.4	0.0	125.4	0.0	0.0
4.4	Withdrawal		114.2	0.0	114.2	0.0	0.0
	Chatham D		131.9	0.0	131.9	0.0	0.0
4.	Total Storage		20,636.5	11,145.8	9,490.8	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		62,221.5	38,769.7	23,451.9	0.0	0.0
5.2	Company Production M13		0.0	0.0	0.0	0.0	0.0
5.3	US Trns. C1		0.0	0.0	0.0	0.0	0.0
5.4	Fuel		16,897.1	10,528.4	6,368.7	0.0	0.0
5.5	Interruptible Margin Rebate		0.0	0.0	0.0	0.0	0.0
5.	Total Transportation		79,118.6	49,298.1	29,820.5	0.0	0.0
6.	SNG Premium		0.0	0.0	0.0	0.0	0.0
	DEHYDRATION						
7.1	Demand		997.6	997.6	0.0	0.0	0.0
7.2	Commodity		185.2	0.0	185.2	0.0	0.0
7.	Total Dehydration		1,182.8	997.6	185.2	0.0	0.0
8.	Total Union		100,937.9	61,441.5	39,496.5	0.0	0.0
	TRANSCANADA						
9.1	STS and Other		10,061.3	10,061.3	0.0	0.0	0.0
9.	Total TransCanada		10,061.3	10,061.3	0.0	0.0	0.0
10.	**TOTAL STORAGE & TRANSP.**	41,688.7	152,688.0	93,008.3	59,679.7	0.0	0.0
11.	**Less Union M13**		0.0	0.0	0.0	0.0	0.0
12.	**Less Union C1**		0.0	0.0	0.0	0.0	0.0
13.	**COST TO OPERATIONS**	41,688.7	152,688.0	93,008.3	59,679.7	0.0	0.0

TECUMSEH GAS
CLASSIFICATION OF COST TO SERVE
2014 TEST YEAR
($000)

Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Storage Space	Col. 1 Transmission & Compression Total	Col. 2 Alloc'tn Ann	Col. 3 Alloc'tn Dly	Col. 4 Annual Demand	Col. 5 Daily Demand	Col. 6 Commodity	Col. 7 Pool Storage Storage Total	Col. 8 Union Transfer	Col. 9 Net Tecumseh	Col. 10 Alloc'tn Ann	Col. 11 Alloc'tn Dly	Col. 12 Annual Demand	Col. 13 Daily Demand	Col. 14 Commodity
	RATE BASE RETURN AMOUNT																			
1.1	Utility Return	45%	55%	16,888.1	7,599.6	9,288.4	7,599.6	35%	65%	2,659.9	4,939.8		9,288.4	0.0	9,288.4	35%	65%	3,251.0	6,037.5	
1.	Total Return			16,888.1	7,599.6	9,288.4	7,599.6			2,659.9	4,939.8		9,288.4	0.0	9,288.4			3,251.0	6,037.5	
	EXPENSES - OPERATION																			
2.1.1	Labour	75%	25%	1,388.2	1,041.1	347.0	1,041.1	35%	65%	364.4	676.7		347.0	20.8	326.2	35%	65%	114.2	212.1	
2.1.2	Supplies & Other	90%	10%	573.4	516.1	57.3	516.1	20%	30%	103.2	154.8	258.1	57.3	3.4	53.9	30%	45%	16.2	24.2	13.5
2.1.3	Hydro	100%	0%	363.0	363.0		363.0	20%	30%	72.6	108.9	181.5				0%	0%			
2.1.4	Lease Rentals	0%	100%	1,597.9		1,597.9		35%	65%				1,597.9		1,597.9	35%	65%	559.3	1,038.6	
2.1.5	Surface Rentals	0%	100%	342.7		342.7		35%	65%				342.7	20.5	322.2	35%	65%	112.8	209.4	
2.1.6	Provision for LUF	87%	13%	4,130.5	3,593.6	537.0	3,593.6	0%	0%			3,593.6	537.0	0.0	537.0	0%	0%			537.0
2.1	Subtotal			8,395.7	5,513.8	2,881.9	5,513.8			540.2	940.4	4,033.2	2,881.9	44.7	2,837.2			802.5	1,484.3	550.5
	MAINTENANCE																			
2.2.1	Company	80%	20%	1,491.1	1,192.9	298.2	1,192.9	20%	30%	238.6	357.9	596.4	298.2	17.8	280.4	30%	45%	84.1	126.2	70.1
2.2.2	Contractor	55%	45%	1,561.0	858.5	702.4	858.5	20%	30%	171.7	257.6	429.2	702.4	42.0	660.4	30%	45%	198.1	297.2	165.1
2.2	Subtotal			3,052.1	2,051.4	1,000.6	2,051.4			410.3	615.5	1,025.6	1,000.6	59.9	940.7			282.2	423.4	235.2
	ADMINISTRATIVE & GENERAL																			
2.3.1	General Office	75%	25%	3,223.7	2,417.8	805.9	2,417.8	35%	65%	846.2	1,571.6		805.9	48.2	757.7	35%	65%	265.2	492.5	
2.3.2	Service Fees	75%	25%	2,409.5	1,807.1	602.4	1,807.1	35%	65%	632.5	1,174.6		602.4	36.0	566.4	35%	65%	198.2	368.1	
2.3.3	Overhead Capitalized	75%	25%	(1,001.8)	(751.3)	(250.4)	(751.3)	35%	65%	(263.0)	(488.3)		(250.4)	0.0	(250.4)	35%	65%	(87.6)	(162.8)	
2.3	Subtotal			4,631.4	3,473.6	1,157.9	3,473.6			1,215.7	2,257.9		1,157.9	84.3	1,073.6			375.8	697.8	0.0
	DEPRECIATION AND AMORTIZATION																			
2.4.1	Depreciation	58%	42%	6,156.5	3,557.5	2,599.0	3,557.5	35%	65%	1,245.1	2,312.4		2,599.0	138.4	2,460.6	35%	65%	861.2	1,599.4	0.0
2.4.2	Amortization	0%	100%	459.8		459.8		35%	65%				459.8	0.0	459.8	35%	65%	160.9	298.9	0.0
2.4	Subtotal			6,616.3	3,557.5	3,058.8	3,557.5			1,245.1	2,312.4		3,058.8	138.4	2,920.4			1,022.1	1,898.3	
	TAXES - OTHER THAN INCOME																			
2.5.1	Municipal	80%	20%	1,405.7	1,124.5	281.1	1,124.5	35%	65%	393.6	730.9		281.1	16.8	264.3	35%	65%	92.5	171.8	
2.5.2	Capital Rate Base Ratio	45%	55%	0.0	0.0	0.0	0.0	35%	65%				0.0			35%	65%			
2.5	Subtotal			1,405.7	1,124.5	281.1	1,124.5			393.6	730.9		281.1	16.8	264.3			92.5	171.8	
2.	**TOTAL EXPENSES**			24,101.1	15,720.8	8,380.3	15,720.8			3,804.9	6,857.1	5,058.8	8,380.3	344.0	8,036.2			2,575.1	4,675.6	785.7
3.	**REVENUE REQUIREMENT**			40,989.2	23,320.5	17,668.7	23,320.5			6,464.8	11,796.9	5,058.8	17,668.7	344.0	17,324.7			5,826.1	10,713.1	785.7
4.1	**GROSS REVENUE REQUIREMENT (incl. fuel)**			40,989.2	23,320.5	17,668.7	23,320.5			6,464.8	11,796.9	5,058.8	17,668.7	344.0	17,324.7			5,826.1	10,713.1	785.7
4.2	**GROSS REVENUE REQUIREMENT (excl. fuel)**			40,989.2	23,320.5	17,668.7	23,320.5			6,464.8	11,796.9	5,058.8	17,668.7	344.0	17,324.7			5,826.1	10,713.1	785.7
3.1.1	Less: UNION GAS									386.8	744.2	312.0						0.0	0.0	0.0
3.1.2	Less: CENTRA GAS									67.6	74.4	54.6						64.8	72.1	9.0
3.1.3	Less: ST. LAWRENCE									0.0	0.0	0.0						0.0	0.0	0.0
3.1	**Net: CONSUMERS GAS**									6,010.4	10,978.3	4,692.2						5,761.3	10,641.0	776.7

Witnesses: A. Kacicnik
M. Kirk

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	6,010.4	6,010.4	0.0	6,010.4	0.0	0.0
1.2	Daily Demand	10,978.3	10,978.3	10,978.3	0.0	0.0	0.0
1.3	In/out	4,692.2	4,692.2	0.0	4,692.2	0.0	0.0
1.4	Fuel	3,152.0	3,152.0	0.0	3,152.0	0.0	0.0
1.5	Transactional Services Revenues	(3,413.6)	(3,413.6)	(2,048.2)	(1,365.5)	0.0	0.0
1.	Total Transmission	21,419.3	21,419.3	8,930.2	12,489.1	0.0	0.0
	STORAGE						
2.1	Annual Demand	5,761.3	5,761.3	0.0	5,761.3	0.0	0.0
2.2	Daily Demand	10,641.0	10,641.0	10,641.0	0.0	0.0	0.0
2.3	In/out	776.7	776.7	0.0	776.7	0.0	0.0
2.4	Transactional Services Revenues	(2,586.4)	(2,586.4)	(1,551.8)	(1,034.5)	0.0	0.0
2.	Total Storage	14,592.6	14,592.6	9,089.2	5,503.4	0.0	0.0
3.	Total Tecumseh	36,011.9	36,011.9	18,019.4	17,992.5	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		8,885.4	0.0	8,885.4	0.0	0.0
4.2	Peak		10,859.9	10,859.9	0.0	0.0	0.0
4.3	Injection		111.7	0.0	111.7	0.0	0.0
4.4	Withdrawal		69.5	0.0	69.5	0.0	0.0
	Chatham D		132.8	0.0	132.8	0.0	0.0
4.	Total Storage		20,059.3	10,859.9	9,199.4	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		63,095.6	39,314.3	23,781.3	0.0	0.0
5.4	Fuel		14,611.1	9,104.0	5,507.1	0.0	0.0
5.	Total Transmission		77,706.7	48,418.4	29,288.4	0.0	0.0
	DEHYDRATION						
6.1	Demand		1,010.8	1,010.8	0.0	0.0	0.0
6.2	Commodity		207.2	0.0	207.2	0.0	0.0
6.	Total Dehydration		1,218.0	1,010.8	207.2	0.0	0.0
7.	Total Union		98,984.0	60,289.1	38,695.0	0.0	0.0
	TRANSCANADA						
8.1	STS and Other		19,695.3	19,695.3	0.0	0.0	0.0
8.	Total TransCanada		19,695.3	19,695.3	0.0	0.0	0.0
9.	**TOTAL STORAGE & TRANSP.**		154,691.2	98,003.8	56,687.5	0.0	0.0
10.	**COST TO OPERATIONS**		154,691.2	98,003.8	56,687.5	0.0	0.0

Witnesses: A. Kacicnik
M. Kirk

TECUMSEH GAS
CLASSIFICATION OF COST OF SERVICE
2015 TEST YEAR

($000)

Item No.		Functional Allocation T/C	Pool	Utility Return & Expenses	Transmission & Compression	Storage Space	Col. 1 Transmission & Compression: Total	Col. 2 Alloc'tn Ann	Col. 3 Dly	Col. 4 Annual Demand	Col. 5 Daily Demand	Col. 6 Commodity	Col. 7 Pool Storage: Storage Total	Col. 8 Union Transfer	Col. 9 Net Tecumseh	Col. 10 Alloc'tn Ann	Col. 11 Dly	Col. 12 Annual Demand	Col. 13 Daily Demand	Col. 14 Commodity
	RATE BASE RETURN AMOUNT																			
1.1	Utility Return	45%	55%	16,984.2	7,642.9	9,341.3	7,642.9	35%	65%	2,675.0	4,967.9		9,341.3	0.0	9,341.3	35%	65%	3,269.5	6,071.9	
1.	Total Return			16,984.2	7,642.9	9,341.3	7,642.9			2,675.0	4,967.9		9,341.3	0.0	9,341.3			3,269.5	6,071.9	
	EXPENSES - OPERATION																			
2.1.1	Labour	75%	25%	1,429.8	1,072.4	357.5	1,072.4	35%	65%	375.3	697.1		357.5	21.2	336.3	35%	65%	117.7	218.6	
2.1.2	Supplies & Other	90%	10%	579.1	521.2	57.9	521.2	20%	30%	104.2	156.4	260.6	57.9	3.4	54.5	30%	45%	16.3	24.5	13.7
2.1.3	Hydro	100%	0%	366.6	366.6		366.6	20%	30%	73.3	110.0	183.3				0%	0%			
2.1.4	Lease Rentals	0%	100%	1,613.9		1,613.9		35%	65%				1,613.9		1,613.9	35%	65%	564.9	1,049.0	
2.1.5	Surface Rentals	0%	100%	346.1		346.1		35%	65%				346.1	20.5	325.6	35%	65%	114.0	211.6	
2.1.6	Provision for LUF	87%	13%	4,854.7	4,223.6	631.1	4,223.6	0%	0%			4,223.6	631.1	0.0	631.1	0%	0%			631.1
2.1	Subtotal			9,190.3	6,183.8	3,006.5	6,183.8			552.8	963.5	4,667.5	3,006.5	45.1	2,961.4			812.9	1,503.7	644.8
	MAINTENANCE																			
2.2.1	Company	80%	20%	1,506.0	1,204.8	301.2	1,204.8	20%	30%	241.0	361.4	602.4	301.2	17.8	283.4	30%	45%	85.0	127.5	70.9
2.2.2	Contractor	55%	45%	1,576.6	867.1	709.5	867.1	20%	30%	173.4	260.1	433.6	709.5	42.0	667.5	30%	45%	200.3	300.4	166.8
2.2	Subtotal			3,082.6	2,071.9	1,010.7	2,071.9			414.4	621.5	1,036.0	1,010.7	59.8	950.9			285.3	427.9	237.7
	ADMINISTRATIVE & GENERAL																			
2.3.1	General Office	75%	25%	3,274.3	2,455.7	818.6	2,455.7	35%	65%	859.5	1,596.2		818.6	48.5	770.1	35%	65%	269.6	500.6	
2.3.2	Service Fees	75%	25%	2,447.2	1,835.4	611.8	1,835.4	35%	65%	642.4	1,193.0		611.8	36.2	575.6	35%	65%	201.5	374.1	
2.3.3	Overhead Capitalized	75%	25%	(1,017.5)	(763.1)	(254.4)	(763.1)	35%	65%	(267.1)	(496.0)		(254.4)	0.0	(254.4)	35%	65%	(89.0)	(165.4)	
2.3	Subtotal			4,704.0	3,528.0	1,176.0	3,528.0			1,234.8	2,293.2		1,176.0	84.7	1,091.3			382.1	709.3	0.0
	DEPRECIATION AND AMORTIZATION																			
2.4.1	Depreciation	59%	41%	6,575.0	3,875.3	2,699.7	3,875.3	35%	65%	1,356.3	2,518.9		2,699.7	138.4	2,561.3	35%	65%	896.5	1,664.9	0.0
2.4.2	Amortization	0%	100%	463.8		463.8		35%	65%				463.8	0.0	463.8	35%	65%	162.3	301.5	0.0
2.4	Subtotal			7,038.8	3,875.3	3,163.5	3,875.3			1,356.3	2,518.9		3,163.5	138.4	3,025.1			1,058.8	1,966.4	
	TAXES - OTHER THAN INCOME																			
2.5.1	Municipal	80%	20%	1,468.8	1,175.0	293.8	1,175.0	35%	65%	411.3	763.8		293.8	17.4	276.4	35%	65%	96.7	179.7	
2.5.2	Capital Rate Base Ratio	45%	55%	0.0	0.0	0.0	0.0	35%	65%				0.0			35%	65%			
2.5	Subtotal			1,468.8	1,175.0	293.8	1,175.0			411.3	763.8		293.8	17.4	276.4			96.7	179.7	
2.	**TOTAL EXPENSES**			25,484.5	16,834.0	8,650.5	16,834.0			3,969.6	7,160.9	5,703.5	8,650.5	345.4	8,305.2			2,635.8	4,787.0	882.5
3.	**REVENUE REQUIREMENT**			42,468.8	24,476.9	17,991.9	24,476.9			6,644.6	12,128.8	5,703.5	17,991.9	345.4	17,646.5			5,905.3	10,858.9	882.5
4.1	**GROSS REVENUE REQUIREMENT (incl. fuel)**			42,468.8	24,476.9	17,991.9	24,476.9			6,644.6	12,128.8	5,703.5	17,991.9	345.4	17,646.5			5,905.3	10,858.9	882.5
4.2	**GROSS REVENUE REQUIREMENT (excl. fuel)**			42,468.8	24,476.9	17,991.9	24,476.9			6,644.6	12,128.8	5,703.5	17,991.9	345.4	17,646.5			5,905.3	10,858.9	882.5
3.1.1	Less: UNION GAS									393.3	757.0	401.0						0.0	0.0	0.0
3.1.2	Less: CENTRA GAS									68.8	75.7	70.1						65.0	72.2	11.7
3.1.3	Less: ST. LAWRENCE									0.0	0.0	0.0						0.0	0.0	0.0
3.1	**Net: CONSUMERS GAS**									6,182.5	11,296.1	5,232.3						5,840.3	10,786.7	870.8

CLASSIFICATION OF
STORAGE AND TRANSPORTATION

($000)

Item No.	Description	Col. 1 Tecumseh O&M	Col. 2 Annual Cost	Col. 3 Deliver-ability	Col. 4 Seasonal Space	Col. 5 Winter	Col. 6 Annual Commodity
	TECUMSEH						
	TRANSMISSION						
1.1	Annual Demand	6,182.5	6,182.5	0.0	6,182.5	0.0	0.0
1.2	Daily Demand	11,296.1	11,296.1	11,296.1	0.0	0.0	0.0
1.3	In/out	5,232.3	5,232.3	0.0	5,232.3	0.0	0.0
1.4	Fuel	3,570.9	3,570.9	0.0	3,570.9	0.0	0.0
1.5	Transactional Services Revenues	(3,458.1)	(3,458.1)	(2,074.9)	(1,383.2)	0.0	0.0
1.	Total Transmission	22,823.8	22,823.8	9,221.2	13,602.5	0.0	0.0
	STORAGE						
2.1	Annual Demand	5,840.3	5,840.3	0.0	5,840.3	0.0	0.0
2.2	Daily Demand	10,786.7	10,786.7	10,786.7	0.0	0.0	0.0
2.3	In/out	870.8	870.8	0.0	870.8	0.0	0.0
2.4	Transactional Services Revenues	(2,541.9)	(2,541.9)	(1,525.1)	(1,016.8)	0.0	0.0
2.	Total Storage	14,955.9	14,955.9	9,261.5	5,694.4	0.0	0.0
3.	Total Tecumseh	37,779.7	37,779.7	18,482.8	19,296.9	0.0	0.0
	UNION GAS						
	STORAGE						
4.1	Space		7,895.2	0.0	7,895.2	0.0	0.0
4.2	Peak		9,649.6	9,649.6	0.0	0.0	0.0
4.3	Injection		401.6	0.0	401.6	0.0	0.0
4.4	Withdrawal		74.8	0.0	74.8	0.0	0.0
	Chatham D		165.2	0.0	165.2	0.0	0.0
4.	Total Storage		18,186.3	9,649.6	8,536.7	0.0	0.0
	TRANSMISSION						
5.1	Demand with comp.		66,852.3	42,064.4	24,787.9	0.0	0.0
5.4	Fuel		12,102.7	7,615.2	4,487.5	0.0	0.0
5.	Total Transmission		78,955.1	49,679.6	29,275.4	0.0	0.0
	DEHYDRATION						
6.1	Demand		1,038.8	1,038.8	0.0	0.0	0.0
6.2	Commodity		220.2	0.0	220.2	0.0	0.0
6.	Total Dehydration		1,259.0	1,038.8	220.2	0.0	0.0
7.	Total Union		98,400.4	60,368.1	38,032.3	0.0	0.0
	TRANSCANADA						
8.1	STS and Other		21,704.1	21,704.1	0.0	0.0	0.0
8.	Total TransCanada		21,704.1	21,704.1	0.0	0.0	0.0
9.	**TOTAL STORAGE & TRANSP.**		157,884.2	100,555.0	57,329.2	0.0	0.0
10.	**COST TO OPERATIONS**		157,884.2	100,555.0	57,329.2	0.0	0.0

FRPO INTERROGATORY #28

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 23

Please provide the company's views on the Natural Gas Market Review recommendation of annual Gas Supply plans approved by the Board.

RESPONSE

The Company's view on the Board's assessment of distributor natural gas supply plans were provided in written comments that were submitted to the Ontario Energy Board as part of the 2014 Natural Gas Market Review[1]. In summary, the Company is of the view that existing regulatory processes are sufficient to assess all elements of gas supply planning.

Should the Board adopt the Board Staff's recommendation to initiate a separate proceeding, the Company believes the proceeding should include the development of a common Board policy in relation to the risk assumed in distributor gas supply plans that takes into consideration unique conditions such as weather, demand, and assets suitable to specific geographical regions.

[1] EB-2014-0289 Enbridge Written Comments filed January 16, 2015, pages 11 through 13.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #29

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 23

Please provide the company's views on the merits and challenges of a Dawn reference price.

RESPONSE

The Company's view on the use of a Dawn reference price was provided in written comments that were submitted to the Ontario Energy Board as part of the 2014 Natural Gas Market Review[1].

[1] EB-2014-0289 Enbridge Written Comments filed January 16, 2015, pages 13 through 16.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #30

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 24

Provide the monthly aggregated deliveries, consumptions and month-end storage balance for each of the Design Criteria listed.

RESPONSE

As discussed in response to FRPO Interrogatory #19 (Exhibit I.D.EGDI.FRPO.19), the Company does not have a detailed analysis regarding the need for incremental storage for 2016 and beyond at this time. When completed, the detailed analysis would likely be based upon a number of assumptions which would include deliveries, consumption and various Design Criteria.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #31

INTERROGATORY

Ref: Exhibit D, Tab 4, Schedule 1, Page 24

Please provide the analysis that underpins the NEXUS proposal.

a) Please ensure that an assessment of the Niagara and Iroquois deliveries are included.

RESPONSE

The landed cost analysis and related assumptions for the precedent agreement that the Company entered into for transportation capacity on the NEXUS Gas Transmission pipeline are documented in the Company's application for pre-approval of a long-term natural gas transportation contract[1] that was filed with the Ontario Energy Board on June 5, 2015 (the "NEXUS Application"). The Company will address any questions related to the NEXUS Application in that proceeding, in accordance with the procedural order to be issued by the Board.

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[1] EB-2015-0175 Enbridge Gas Distribution Inc. Pre-Approval of a Long-Term Natural Gas Transportation Contract, Exhibit A, Tab 3, Schedule 1, Appendix B and C.

Witnesses: D. Small
A. Welburn

VECC INTERROGATORY #1

INTERROGATORY

Reference: D/T4/S1/ Gas Supply Plan Memorandum/pg. 18 (PDF pg.318)

a) Please confirm that EGD is seeking to close both the DDCTDA and UDCDA 2014 accounts and replace it with a single UDCDA account.

b) If this is confirmed please explain what the original intent was of having separate accounts and why this is no longer deemed necessary.

RESPONSE

a) and b) Confirmed. The Company is seeking to close both the 2014 DDCTDA and the 2014 UDCDA. As approved in the EB-2012-0459 Decision with Reasons, at page 66, the DDCTDA was to be discontinued after 2014. As approved in the 2015 Rate Adjustment proceeding (EB-2014-0276), the 2015 UDCDA has been established to record the actual cost consequences of unutilized transportation capacity contracted by the Company to meet its Peak Day requirements in 2015. This is confirmed in the EB-2014-0276 Accounting Order.

Please see the response to Board Staff Interrogatory #1 (Exhibit I.C.EGDI.STAFF.1) for further details on these accounts.

Witnesses: D. Small
A. Welburn

VECC INTERROGATORY #2

INTERROGATORY

Reference: D/T4/S1/ Gas Supply Plan Memorandum/pg. 19 (PDF pg.319)

a) EGD has stated that it assumed 200,000 GJ/day of Niagara Falls to Enbridge Parkway capacity on TCPL. Was there any restriction on acquiring more than the 200,000 GJ of Supply/Transportation from Niagara? If not, why was this amount chosen?

RESPONSE

The transportation capacity offered on this path by TransCanada in its July 2013 capacity open season was limited to 200,000 GJ/day.

Witnesses: D. Small
A. Welburn