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June 24, 2016

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")
2015 Earnings Sharing Mechanism and Other Deferral and Variance Accounts Clearance Review
Ontario Energy Board File No. EB-2016-0142

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

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

Please contact the undersigned if you have any questions.

Yours truly,

{Original Signed}

Trina Wright
Regulatory Coordinator

cc: Mr. D. Stevens, Aird & Berlis LLP
All Interested Parties EB-2016-0142 (via email)

BOMA INTERROGATORY #1

Interrogatory

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

Please explain what the "EGD corporate trial balance" is. How does it differ from the 2015 corporate financial statements and from the audited consolidated income at Exhibit B, Tab 1, Schedule 4, Page 1.

Response

The reference to the Enbridge Ontario corporate trial balance, included at Exhibit B, Tab 1, Schedule 1, page 5, refers to Enbridge Gas Distribution Inc.'s ("EGDI") corporate results, excluding the impact of its wholly owned subsidiary St. Lawrence Gas Company Inc. ("St. Lawrence"). The impact of St. Lawrence is however included within the audited consolidated corporate financial statements and income statement, referred to in Exhibit B, Tab 1, Schedule 4.

Witness: R. Small

BOMA INTERROGATORY #2

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 3, Pages 1-2

(a) What, in EGD's view, accounted for the migration of customers from interruptible to firm service? When did the migration occur, i.e. over what period of time? What was the extent of the migration, in volume terms and numbers of customers? What additional firm capacity in 2016 was caused by this migration?

(b) What amount of 332 revenue had been included in 2015 Board approved rates?

Response

a) Please see the response to IGUA Interrogatory #1 (Exhibit I.B.EGDI.IGUA.1) for the causes of customer migration from Interruptible to Firm Service. The migration occurred from Interruptible to Firm service during the customers' annual re-contracting process and began in the Summer and Fall of 2014. As also described in IGUA #1, a forecasted amount of migration was included in the 2015 budget process (see EB-2016-0142 Exhibit B, Tab 3, Schedule 2), however, 35 additional interruptible customers above the forecasted number requested a switch to Firm service which represents an additional 141.1 10^6m^3 moving from Rate145/170 to Rate 110.

   There was no need for additional firm capacity required as part of the 2016 budget process.

b) 2015 Board Approved rates (EB-2014-0276) were designed to reflect the recovery of $2.1 million in revenues through Rate 332.

Witnesses: R. Cheung
C. Ho
R. Small

BOMA INTERROGATORY #3

Interrogatory

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

(a) Please describe the US GAAP adjustment elimination of (444.2).

(b) In c), please explain the reason for the " Elimination of interest on deferral accounts" and " Elimination of allowable interest during construction". Are these interest payments not being charged to ratepayers?

Response

a) For a description of the U.S. GAAP adjustment elimination please refer to the response to FRPO Interrogatory #6, found at Exhibit I.B.EGDI.FRPO.6.

b) For further explanation of the identified eliminations please refer to the response to BOMA Interrogatory #6, found at Exhibit I.B.EGDI.BOMA.6.

Witness: R. Small

BOMA INTERROGATORY #4

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 2, Page 7

Why were the "retirements" shown as positive numbers in column 2? Please explain fully, including how asset retirements are dealt with in the depreciation account

Response

As prescribed in the Board's Uniform System of Accounts for "Class A" Gas Utilities, the ordinary retirement of a depreciable asset requires that its book value be credited to gross plant, with a corresponding debit to accumulated depreciation. Following retirement, depreciation of the asset stops.

Witness: R. Small

BOMA INTERROGATORY #5

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 4

(a) Please provide a full explanation for the $191.4 million overrun for the GTA Reinforcement Project.

(b) What amount of the $11.7 million Customer Growth overspend was increased municipal fees, and how much was due to full year construction? Was full year construction not included in Board approved budget?

(c) What is the difference in cost/customer between a replacement (conversion) customer and new construction (subdivision) customer? Please explain the causes for the difference.

Response

a) Please see the response to CME Interrogatory #3(a) at Exhibit I.D.EGDI.CME.3.

b) The increased costs for Customer Growth (as compared to budget forecasts prepared for the Custom IR case) were driven by a number of factors. These include the following:

- Budgeted costs did not anticipate the extreme winter conditions encountered in 2015
- Higher municipality fees
- Increased labour costs
- Increased material costs
- Changes in excavating requirements have resulted in significant increases in hydrovac usage and associated disposal costs

c) The cost to add a residential replacement customer is significantly higher than the cost to add a subdivision customer. There are multiple challenges that the Company encounters when installing a replacement customer. The following are some examples:

- Installations in rocky/rough terrain environments

- Conflicts with other utilities (may require more depth, possible delays)
- Dewatering
- Expensive restorations
- Previous road cuts

Conversely, subdivision customers typically would not have the challenges described above. Restorations would be minimal by comparison. There are cost efficiencies where subdivision customers are concerned. For example, joint utility trenching is a common practice where multiple utilities have access to the trench at the same time and all utilities share the cost of digging the trench.

BOMA INTERROGATORY #6

Interrogatory

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

Please explain further the adjustments to EGD's corporate revenue in items 18, 20, and 24.

Response

The Line 18 adjustment referenced at Exhibit B, Tab 3, Schedule 1, page 5, refers to the elimination of the interest expense offset (or credit) recorded in the corporate financials to recognize interest charged to construction work-in-progress (interest during construction), which is ultimately capitalized to the property, plant, and equipment component of rate base once assets are placed into service. The interest credit is eliminated as the allowable utility interest expense is calculated through the utility capital structure that funds rate base, which only includes assets in service.

The Line 20 adjustment referenced at Exhibit B, Tab 3, Schedule 1, page 5, refers to the elimination of the interest calculated on deferral and variance accounts (carrying cost), which during 2015 were in a net receivable position. The amount is eliminated as the Company is allowed to recover (or required to pay) the carrying cost on most deferral and variance account balances, which are not included within rate base, at Board approved rates.

The Line 24 adjustment referenced at Exhibit B, Tab 3, Schedule 1, page 5, refers to the elimination of dividend income received as a result of the non-utility inter-company financing transaction originally approved by the Board in EBO 179-16. An interest expense incurred in relation to the financing transaction is similarly eliminated, as shown as part of the Line 14 adjustment referenced at Exhibit B, Tab 4, Schedule 1, page 6.

Each of the above adjustments is consistent with adjustments made in prior year utility actual results, and Board approved results.

Witness: R. Small

BOMA INTERROGATORY #7

Interrogatory

Ref: Exhibit B, Tab 4, Schedule 1, Page 3

Please explain fully the calculation of the income tax credit of $41.4 million in line 26

Response

In the determination of utility stand-alone income taxes, the income tax credit of $41.4 million, shown at line 26 of Exhibit B, Tab 4, Schedule 1, page 3, represents the income tax shield provided by utility interest expense. Utility interest expense results from the determination of the return component of debt within the actual 2015 utility capital structure, multiplied by actual utility rate base. The credit recognizes the tax deductibility of interest expense. Details of the calculation of the credit are provided at Lines 22 through 25 of Exhibit B, Tab 4, Schedule 1, page 3.

Witness: R. Small

BOMA INTERROGATORY #8

Interrogatory

Ref: Exhibit B, Tab 4, Schedule 1, Page 4

Please explain the accounting treatment of amortization in line 4.

Response

As referenced in the explanation to Line No. 4 (Exhibit B, Tab 4, Schedule 1), contained on page 5 of Exhibit B, Tab 4, Schedule 1, the amortization amount of $22.5 million on Line 4 represents the amortization of the purchase price discrepancy ("PPD"), or premium, or fair value adjustment, paid by EGD's ultimate parent Enbridge Inc., upon its acquisition of Enbridge Gas Distribution Inc. (formerly The Consumers Gas Company Ltd.). Effective January 1, 2012, EGD commenced utilizing U.S. GAAP for external/corporate financial reporting purposes. Under US GAAP, EGD elected to apply push-down accounting in respect of its original acquisition by its ultimate parent, Enbridge Inc. On the original acquisition, the PPD and corresponding amortization was recorded within Enbridge Inc.'s financial statements, rather than EGD's. Upon adopting push-down accounting, recognition of the outstanding PPD, and its corresponding amortization, has been recorded within EGD's financial statements. The impact of recognizing the PPD impacts within EGD's financial statements has been subsequently eliminated from utility results, as the impacts do not pertain to utility operations.

Witness: R. Small

CCC INTERROGATORY #1

Interrogatory

Ref: (Ex. B/T1/S3/p. 2)

Please describe the transaction that resulted in the sale of base pressure gas of $5.8 million. Please explain how the $5.8 million amount was derived.

Response

In the EB-2015-0114 Settlement Agreement (2016 Rates), Enbridge agreed that it would include the profits from the 2015 sale of approximately 2 Bcf of base pressure gas as part of the 2015 utility earnings to be considered in the determination of the ESM amount for 2015.

The sale of base pressure gas was executed on a number of days over the March/April, 2015 timeframe on the NGX trading platform at daily market prices.

The $5.8 million profit from the sale of base pressure gas was derived by taking the sum of the total proceeds (sale price multiplied by volume for each daily transaction) and subtracting book value.

Book value was based on the $40.9 million cost of base pressure gas in fixed assets, averaged over the 41.5 Bcf of base pressure gas prior to sale, or $0.985/MMBtu.

Total proceeds were $7.769 million, book value of the gas sold was $1.970 million, for a gain of $5.799 million.

Witnesses: B. Black
R. Small

CCC INTERROGATORY #2

Interrogatory

Ref: (Ex. B/T2/S4/p. 1)

The LTC- GTA Reinforcement Costs are $191.4 million over budget. Please provide a detailed calculation setting out how the $191 was derived. How much is related to increased total project costs and how much is related to carryover costs due to delays? Please explain how these increased costs have impacted 2015 earnings.

Response

Please see the response to CME Interrogatory #3(a) at Exhibit I.D.EGDI.CME.3. The capital expenditure overage had no 2015 earnings impact, as no amounts related to the GTA project were closed into service during 2015.

Witnesses: L. Au
T. Knight

CCC INTERROGATORY #3

Interrogatory

Ref: (Ex. B/T4/S2/p. 2)

Please explain why there was such a significant variance between forecast and actual severance payments in 2015? Will this result lower overall Human Resource costs in 2016 and beyond?

Response

Forecasted severances represent regular severances that may occur as part of Enbridge's regular operations. The actual severances in 2015 also included severances from a one time workforce reduction across all of Enbridge. This resulted in additional severance costs of approximately $12M pre-tax. This workforce reduction occurred in November 2015, therefore it is expected that in 2016 and beyond Enbridge will benefit from lower employee costs.

Witnesses: A. Patel
L. Stickles

CME INTERROGATORY #1

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 4

At Table 1, EGD provides a summary of capital expenditures comparing the 2015 actuals to the 2015 Board-approved budget. That Table shows that the total capital expenditures for 2015 were $1,015.4M. This represents a spend of $183M in excess over the Board-approved budget of $832M.

(a) From CME's review of the major drivers for this overspend, it appears that a significant portion is caused by a variety of delays that occurred in 2014. Please reproduce Table 1, "Summary of Capital Expenditures 2015 Actual and 2015 Board-Approved Budget" to include the 2014 actual and the 2014 Board-approved budgets; and

(b) Table 1 shows that for system improvements and upgrades, EGD actually spent $208.5M instead of the Board-approved budget of $247.8M which represents an underspend of $39.3M. Please provide a more fulsome explanation of the system improvements and upgrades that were not undertaken in 2015.

Response

a) Please see the following Table 1. Note that there has been some re-grouping of 2014 costs since the EB-2015-0122 filing (see Exhibit B, Tab 2, Schedule 4), to reflect the current classification of spending across the listed “Core” Capital Expenditures categories. The re-grouping does not result in any change to the total 2014 expenditures for “Core” Capital Expenditures.

Witnesses: L. Au
T. Knight

Table 1
Summary of Capital Expenditures

	($Millions)	Col 1 Actual 2014	Col 2 Board Approved Budget 2014	Col 3 Actual Over/(Under) 2014	Col 4 Actual 2015	Col 5 Board Approved Budget 2015	Col 6 Actual Over/(Under) 2015
A	Customer Related Distribution Plant	154.1	122.4	31.7	145.5	130.4	15.1
B	System Improvements and Upgrades	191.2	243.2	(52.0)	208.5	247.8	(39.3)
C	General and Other Plant	54.5	56.3	(1.8)	55.8	52.7	3.1
D	Underground Storage Plant	12.8	21.9	(9.1)	26.9	15.7	11.2
E	**Sub total "Core" Capital Expenditures**	**412.6**	**443.8**	**(31.2)**	**436.7**	**446.6**	**(9.9)**
F	Work and Asset Management System (WAMS)	19.6	36.3	(16.7)	27.6	25.7	1.9
G	Leave to Construct - Major Reinforcements	180.1	231.4	(51.3)	551.1	359.7	191.4
H	**Sub total Special Initiatives**	**199.7**	**267.7**	**(68.0)**	**578.7**	**385.4**	**193.3**
I	**Total Capital Expenditures**	**612.3**	**711.5**	**(99.2)**	**1,015.4**	**832.0**	**183.4**

b) The following Table 2 provides a detailed breakdown of the $39.3M variance related to System Improvement and Upgrades, with explanations provided further below.

Table 2
System Improvement and Upgrades
2015 Actual vs. 2015 Board Approved Budget Major Variance
($millions)

		Actual Over/(Under)
	Total 2015 Variance	**(39.3)**
A	Reinforcements	(12.2)
B	Relocations	(8.4)
C	System Integrity and Reliability	(1.1)
D	Departmental Labour Costs, AG and IDC	(17.6)
		(39.3)

A. Reinforcements – Underspent by $12.2 Million

Actual growth was considerably less than budgeted growth, which was based on forecasts received from developers. York Region Reinforcement ($10 million) was deferred until 2018 and Alliston Reinforcement ($1 million) was deferred indefinitely.

Witnesses: L. Au
T. Knight

The remaining variance is due to the deferral of several smaller reinforcements.

B. Relocations - Underspent - $8.4 Million

Relocation activity is directly dependent on third party infrastructure timelines. The 2015 variance is primarily due to credits from third parties associated with large scale infrastructure work such as, York Region Rapid Transit and Metrolinx.

C. System Integrity and Reliability (SIR) – Underspent by $1.1 Million

Details of the 2015 SIR activities and expenditures are set out in Exhibit D, Tab 1, Schedule 4.

D. Departmental Labour Costs, A&G and IDC – Underspent $17.6 Million

These allocations include departmental labour costs, capitalized administrative and general and interest during construction. These allocations are prorated to asset categories based on direct capital expenditures for each category. The underspend variance in allocations for System Improvement and Upgrades is driven by two factors. Firstly, total allocations were underspent compared to the budget by $9.9M. As shown in Exhibit B, Tab 2, Schedule 4, Table 2 and explained at paragraph 10 of that evidence, the underage was driven by a reduced workforce, lower Interest During Construction ("IDC") and partially offset by higher capitalized administrative and general costs. This underspend means that the total allocations to each category of capital expenditures was less than budget. Secondly, the allocation underage for System Improvement and Upgrades is a result of direct capital underspending in the System Improvement and Upgrades category as this causes a lower proration. The total allocations by asset category for 2015 are set out in the following Table 3.

Table 3
Allocations - Departmental Labour Costs, A&G and IDC

Item		Col 1 Actual 2015	Col 2 Board Approved Budget 2015	Col 3 Actual Over/(Under) 2015
1	Customer Related	35.9	29.3	6.6
2	System Improvement	64.9	82.5	(17.6)
3	General Plant	3.6	3.4	0.2
4	Storage	2.8	1.9	0.9
5	Total Allocations	107.2	117.1	(9.9)

Witnesses: L. Au
T. Knight

CME INTERROGATORY #2

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 4, page 3 of 5

With respect to facilities and general plant, EGD states that the tools and fleet equipment replacements were accelerated to meet "safety and reliability" concerns. This represented an overspend of $7.1M. Please provide a description of the exact safety and reliability concerns, and the corresponding requirement to replace tools and fleet equipment. In providing this description, please identify whether any of the safety and reliability concerns are reflected in revised safety standards or other government regulations.

Response

Table 1
Fleet, Tools and Equipment
2015 Actual vs. 2015 Board Approved Budget Major Variance
($millions)

		Actual Over/(Under)
A	Fleet and Heavy Work Equipment	5.4
B	Tools and Work Equipment	1.7
		7.1

A. Fleet and Heavy Work Equipment Over $5.4 Million

The overspend represents purchases of fleet and heavy work equipment required to replace obsolete assets. The replacements were necessitated by the condition of the assets, not by changes in Government regulations. Unreliable vehicles affect the Company's ability to respond to emergencies and impact the safety of our drivers. 140 fleet vehicles met the Company criteria for replacement, which is seven years or 250,000 km. Additionally, three loader backhoes and three mini excavators were replaced. These assets had over 7,000 working hours and were incurring increased operating and maintenance costs due to the age of the asset. Unreliable heavy work equipment affects the Company's ability to respond to emergencies and perform routine operations.

B. Tools and Work Equipment Over $1.7 Million

The overage is driven by the replacement of various obsolete gas monitoring devices, older keyhole tools and obsolete gas surveyors for improved reliability.

The replacements were necessitated by the condition of the assets, not by changes in Government regulations. Unreliable equipment affects the Company's ability to respond to emergencies and perform routine operations. Small tools which were replaced include, but are not limited to, the following items which are required for day to day operations: squeeze off tools, concrete saws, jack hammers, pumps etc.

Witnesses: L. Au
T. Knight

ENERGY PROBE INTERROGATORY #1

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 1

Did Enbridge make any changes to its accounting practices that affect 2015 results? If yes, please explain these changes and indicate why they were made.

Response

During 2015, Enbridge did not make any material changes in accounting practices. 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, 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: J. Barradas
R. Small

ENERGY PROBE INTERROGATORY #2

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 Enbridge's previous earning sharing calculations for 2014?

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

Response

a) Yes, the adjustments made between 2015 audited consolidated income and utility income are consistent with the adjustments made in Enbridge’s previous earnings sharing calculations for 2014, and in the presentation of utility results for prior years.

Witness: R. Small

FRPO INTERROGATORY #1

Interrogatory

REF: Exhibit B, Tab 1, Schedule 3, Page 1, lines 1 and 4

1) Please provide the actual, normalized and budgeted volumes and the underlying commodity prices that support lines 1 and 4 on a quarterly basis for 2015.
   a) If the normalized amounts are not prepared in this way, please explain how the analysis is done and how the weighted average effect of seasonal consumption is accounted for in the analysis.

Response

Sales Volumes				
	Actual Volumes (10^6m^3)	Adjustment (10^6m^3)	Normalized Volumes (10^6m^3)	Budget Volumes (10^6m^3)
Q1	4,164.3	(625.1)	3,539.2	3,617.2
Q2	1,498.3	(41.9)	1,456.4	1,482.2
Q3	522.3	-	522.3	513.2
Q4	1,544.5	188.4	1,732.9	1,787.9
Annual	7,729.4	(478.6)	7,250.8	7,400.5
T-Service Volumes				
	Actual Volumes (10^6m^3)	Adjustment (10^6m^3)	Normalized Volumes (10^6m^3)	Budget Volumes (10^6m^3)
Q1	1,824.3	(196.9)	1,627.4	1,578.6
Q2	908.5	(8.6)	899.9	854.2
Q3	562.6	-	562.6	506.4
Q4	907.0	58.1	965.1	947.9
Annual	4,202.4	(147.4)	4,055.0	3,887.1
Total Volumes				
	Actual Volumes (10^6m^3)	Adjustment (10^6m^3)	Normalized Volumes (10^6m^3)	Budget Volumes (10^6m^3)
Q1	5,988.6	(822.0)	5,166.6	5,195.8
Q2	2,406.8	(50.5)	2,356.3	2,336.4
Q3	1,084.9	-	1,084.9	1,019.6
Q4	2,451.5	246.5	2,698.0	2,735.8
Annual	11,931.8	(626.0)	11,305.8	11,287.6

Line 1 of Exhibit B, Tab 1, Schedule 3 shows total normalized revenues and Board approved revenues from sales customers. Total normalized sales revenues of

Witnesses: R. Cheung
C. Ho

$2,442.8 million is determined based on total normalized sales volume of 7,250.8 10^6m^3, as calculated by taking total annual sales volumes of 7,729.4 10^6m^3 less weather adjustment of 478.6 10^6m^3. The underlying commodity prices used to calculate revenues are in accordance with each quarter's rate change filing (QRAM), which includes EB-2014-0348 for the first quarter, EB-2015-0027 for the second quarter, EB-2015-0163 for the third quarter, and EB-2015-0242 for the fourth quarter. Board approved unit rates in the above mentioned QRAM filings are applied to both actual volumes and weather adjusted volumes for each rate class in order to arrive at total normalized sales revenues of $2,442.8 million.

Board approved sales revenues of $2,458.9 million is determined based on total budget sales volumes of 7,400.5 10^6m^3 and budget revenue rates as filed in EB-2014-0276.

Total gas costs of $1,724.3 million in Line 4 of Exhibit B, Tab 1, Schedule 3 is determined based on applying PGVA reference prices as previously filed at each QRAM to normalized sales volumes and applying QRAM TCPL toll rate to Western T-Service volumes.

Board approved gas cost budget of $1,694.2 million is similarly determined based on applying budget PGVA reference prices and TCPL toll rate to budgeted volumes as filed in EB-2014-0276.

Witnesses: R. Cheung
C. Ho

FRPO INTERROGATORY #2

Interrogatory

REF: Exhibit B, Tab 1, Schedule 4, Page 4, paragraph E and Exhibit D, Tab 1, Schedule 3 and Exhibit D, Tab 3, Schedule 1, pages 31-40

Preamble: Paragraph E states: *"The overall project spend is expected to catch up to budgeted project spend by the project completion in 2016. The delayed in-service date is due to design complexities.".*

Schedule 3 page 1 states: "*The actual costs incurred as at December 31, 2015 were $47.2 million versus the cumulative forecast of $62.5 million to the end of 2015 that was presented in the EB-2012-0459 proceeding. The current forecast of costs remaining to complete the project is approximately $32.5 million, for a total cost of approximately $80 million. This is somewhat higher than the $70.6 million forecast of total costs presented in the EB-2012-0459 proceeding."*

Page 32 states: "*Existing Technology is problematic because it is based on an operating system that will no longer be software vendor supported after 2015."*

Please reconcile the two statements.

a) Is the project forecasted to be $10 million overspent?
b) Who is at risk for the over-expenditure?

Response

a) The forecast provided within Exhibit D, Tab 1, Schedule 3 is more recent and outlines the forecasted spend for the WAMS project to be approximately $80M, which is higher than the $70.6 million original forecasted spend.

b) During the Custom IR term, the rate base value for the WAMS project is fixed at the $70.6 million forecast. Rates will be set for the relevant years (2016 to 2018) using that rate base value. The full costs of the WAMS project will be subject to review in a future proceeding when the actual costs and timing of the WAMS project are relevant to relief being sought.

Witnesses: W. Akkermans
B. Misra

FRPO INTERROGATORY #3

Interrogatory

REF: Exhibit B, Tab 1, Schedule 4, Page 4, paragraph E and Exhibit D, Tab 1, Schedule 3 and Exhibit D, Tab 3, Schedule 1, pages 31-40

Preamble: Paragraph E states: *"The overall project spend is expected to catch up to budgeted project spend by the project completion in 2016. The delayed in-service date is due to design complexities.".*

Schedule 3 page 1 states: "*The actual costs incurred as at December 31, 2015 were $47.2 million versus the cumulative forecast of $62.5 million to the end of 2015 that was presented in the EB-2012-0459 proceeding. The current forecast of costs remaining to complete the project is approximately $32.5 million, for a total cost of approximately $80 million. This is somewhat higher than the $70.6 million forecast of total costs presented in the EB-2012-0459 proceeding."*

Page 32 states: "*Existing Technology is problematic because it is based on an operating system that will no longer be software vendor supported after 2015."*

Is the existing technology being supported?

a) If so, how?
b) If not, what are the risks and how are they being managed?

Response

The existing technology and the operating system are officially no longer supported by Microsoft, and any issues encountered are addressed on a "best effort" basis only. In addition, security patches and fixes to vulnerabilities are not provided due to obsolesce of the operating system and the underlying infrastructure. This exposes the existing technology to external security threats and system instability. In an effort to manage these risks, the system has been isolated from rest of the operating infrastructure and the number of new system changes that are driven by business needs have been minimized. Business continuity plans have also been recently reviewed and validated.

Witnesses: W. Akkermans
B. Misra

FRPO INTERROGATORY #4

Interrogatory

Preamble: "*C – Storage over-spent by $10.3 million*"

How much of the over-expenditure was allocated to the non-utility storage account.

a) Please explain the basis for the amount.

Response

The $10.3 million of overspend related to Underground Storage Plant is detailed in Table 1 below. There were no allocations to the non-utility storage account as all of these capital projects relate to utility assets (the projects are described in EB-2012-0459, Exhibit B2, Tab 6, Schedule 1). Detailed explanations of the spending variances are provided further below.

Table 1
Storage Plant
2015 Actual vs. 2015 Board Approved Budget Major Variance
($millions)

		Actual Over/(Under)
	Total 2015 Variance	**10.3**
A	Tecumseh Compressor Plant	7.8
B	Other	4.8
C	Compressor Programs	0.1
D	Observation Wells	(2.4)
		10.3

Witnesses: L. Au
T. Knight

A. Tecumseh Compressor Plant – Overspent $7.8 Million

Construction of the Administration/Control Building at the Compressor Plant facility (forecasted to commence in 2014) was delayed. The 2015 overspend represents carryover costs from 2014. The project was completed in 2015. The total project was estimated to cost $14.3 million over a two year period. The actual cost was $15.5 million.

B. Other Capital Work – Overspent $4.8 Million

Considerably more capital work was completed in 2015 than originally planned. This included the drilling of two horizontal wells in the Wilkesport reservoir, Wilkesport gathering line modifications, Control Room transition work, and the construction of a new motor control generator boiler and transmission valve automation.

C. Compressor Programs – Overspent $0.1 Million

A colder winter and lower injection pressures resulted in more engine hours and overhauls than originally planned.

D. Observation Wells – Underspent $2.4 Million

The planned work was deferred due to higher priority work as described in paragraph B.

Witnesses: L. Au
T. Knight

FRPO INTERROGATORY #5

Interrogatory

Preamble: "*C – Storage over-spent by $10.3 million*"

Please provide an update on the observation wells planned to be drilled to support a recalculation of LUF in 2017.

a) Will Enbridge be able to file the recalculated LUF in support of its re-basing application?

Response

As stated in EB-2012-0459, Exhibit B2, Tab 6, Schedule 1, Attachment 4, page 1; The additional information gained from observation wells, when used in conjunction with previously held information, will provide Enbridge with a much better understanding of its storage reservoirs and, thereby, of its stored gas inventories. Enbridge had planned to drill two observation wells in each year from 2014 to 2016. Due to a variety of challenges related to agreements with landowners as well as other gas storage operation priorities, Enbridge has not drilled any additional observation wells through this period. Enbridge plans to drill an observation well into the Dow Moore reservoir in 2017.

a) Despite the fact that the observation well drilling program has fallen behind schedule, there were six observation wells added between 2012 and 2014 that will provide new reservoir information that could be applied to an LUF study. Enbridge expects to file a recalculated LUF study in its re-basing application.

Witness: B. Black

FRPO INTERROGATORY #6

Interrogatory

REF: Exhibit B, Tab 3, Schedule 1, Page 4

Please provide a breakdown of the $444M adjustment into its component parts and provide an simple explanation for the adjustment.

Response

Since the Company's adoption of U.S. GAAP for financial reporting purposes, which began in 2012, the Company has recorded entries within its financial results to gross-up revenues and expenses to reflect the clearance (or amortization) of certain deferral and variance accounts (regulatory assets and liabilities), the impacts of which were not previously recognized on the statement of earnings. The entries are performed to ensure compliance with U.S. GAAP. While the Company found that U.S. GAAP standards did not provide specific guidance on the clearance of deferral and variance accounts, it did find that the predominant accounting policy followed by peer companies (reporting under U.S. GAAP) was to gross-up revenues and expenses to reflect amounts refunded/collected in rates during the year. The net impact of the adjusting entries has no earnings impact, as the adjustment to revenues is fully offset by a corresponding adjustment to expenses. This can be seen in the combined impact of the elimination/adjusting entries to utility gas sales (shown at Exhibit B, Tab 3, Schedule 1, page 3, Line 1 with corresponding explanation on page 4), gas costs (shown at Exhibit B, Tab 4, Schedule 1, page 4, Line 1 with corresponding explanation on page 5, and O&M (shown at Exhibit B, Tab 4, Schedule 1, page 3, Line 2 with corresponding explanation on page 5). The adjustments are eliminated from the presentation of actual utility results in order to provide alignment with how Board approved rates are established. The adjustment amount relates predominantly to amounts cleared in relation to the PGVA.

Witness: R. Small

FRPO INTERROGATORY #7

Interrogatory

REF: Exhibit B, Tab 3, Schedules 2 and 3

Using Rate 6 as an example, please provide the monthly forecasted and actual HDD and volumes and demonstrate a reconciliation to the annual totals for actual and normalized.

a) The working papers, preferably in Excel format, to support this calculation and a simple explanation would be sufficient.

Response

	Rate 6 Actual Volumes (10^6 m^3)	*Less: Adjustment (10^6 m^3)*	Normalized Volumes (10^6 m^3)	Rate 6 Budget Volumes (10^6 m^3)	2015 Actual Over (Under) 2015 Budget with Adjustments (10^6 m^3)	Actual Degree Days	Budget Degree Days	Variance from Budget
Jan	806.6	(35.2)	771.4	771.7	(0.3)	782.4	682.0	100.4
Feb	946.2	(168.8)	777.4	796.2	(18.8)	846.8	596.0	250.8
Mar	903.8	(196.4)	707.4	704.0	3.4	602.5	506.0	96.5
Apr	583.5	(68.4)	515.1	527.7	(12.6)	317.6	306.0	11.6
May	278.6	48.8	327.4	313.2	14.2	83.1	133.0	(49.9)
Jun	151.9	0.0	151.9	133.1	18.8	28.4	27.0	1.4
Jul	117.4	0.0	117.4	95.3	22.1	1.4	0.0	1.4
Aug	108.7	0.0	108.7	101.3	7.4	4.4	5.0	(0.6)
Sep	114.6	0.0	114.6	122.0	(7.4)	35.9	59.0	(23.1)
Oct	182.0	(15.6)	166.4	184.5	(18.1)	243.7	238.0	5.7
Nov	340.3	27.4	367.7	351.5	16.2	339.1	392.0	(52.9)
Dec	473.2	107.9	581.1	594.6	(13.5)	424.2	592.0	(167.8)
	5,006.6	(300.3)	4,706.3	4,695.0	11.3	3,709.5	3,536.0	173.5

Using Rate 6 as an example, the 2015 total actual volumes of 5,006.6 10^6m^3 is 311.6 10^6m^3 above the 2015 Board Approved Budget of 4,695.0 10^6m^3. The increase is primarily attributable to the colder than budgeted weather of 173.5 degree days, resulting in weather – normalization adjustment of 300.3 10^6m^3. On a monthly basis, actual volumes are adjusted up or down depending on degree days variance between actual and budget. Colder weather results in an adjustment down and warmer weather results in an adjustment up to arrive at normalized volumes. On a weather-normalized basis, the 2015 actual volumes is 11.3 10^6m^3 higher than the 2015 Budget as shown at the table above.

Witnesses: R. Cheung
C. Ho

FRPO INTERROGATORY #8

Interrogatory

REF: Exhibit B, Tab 3, Schedule 5

Please provide a more specific reference(s) that drove the $1.8M adjustment along with the justification for adding it in this proposed approach.

Response

At page 29 of the Board's EB-2012-0459 Decision With Reasons, dated July 17, 2014, the Board found that Enbridge's Other Revenue (inclusive of Other Income) forecast should be increased to the 2013 actual level of $42.8 million for the duration of the Custom IR term. For 2015, the Board's Decision resulted in an increase to Other Revenue of $1.8 million, as compared to the Company's originally filed forecast of $41.0 million. The $1.8 million increase, and revised Other Revenue amount were shown in the EB-2012-0459 Decision and Rate Order, dated August 22, 2014, at Appendix A, page 13, Rows 4 and 6. Within Enbridge's 2015 Rate Adjustment proceeding, EB-2014-0276, Other Revenue in the amount of $42.8 million was maintained, as was ordered in EB-2012-0459.

While the EB-2012-0459 Decision With Reasons ordered an increase to the gross level of Other Revenue, it did not provide any direction as to how the increase would be achieved or apportioned among the various categories of Other Revenue. As a result, when presenting the Board approved Other Revenue amount, the Company has included the adjustment as part of Miscellaneous and Other Income.

Witnesses: S. Purba
R. Small

FRPO INTERROGATORY #9

Interrogatory

REF: Exhibit B, Tab 4, Schedule 2

Please provide the actual values for the 3 components of STIP for 2015 and for 2014 for comparison.

a) Please explain how the changes result in an increase to 30% over budget in 2015 versus 10% over budget in 2014.
b) Please provide the original basis for the budget i.e., what performance metrics were assumed to establish the budget.

Response

Components of STIP	2014	2015
Company Wide	0.70	1.20
Business Unit Performance	1.36	1.54
Individual Performance	1.20	1.50

a) From the above, it can be seen that in 2015 all three components of STIP were higher than 2014 resulting in a larger increase over budget in 2015 vs. 2014.

b) Similar to 2014, the basis for the budget was that performance for all three STIP components would be 1.0.

Witnesses: A. Patel
L. Stickles

IGUA INTERROGATORY #1

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 3, page 2.

The evidence identifies the main driver of a distribution margin increase of $8.6 million to migration of large volume customers from interruptible to firm rate classes.

(a) Please provide EGD's view of the causes of such migration, and whether additional migration is expected in the coming years.

(b) Please provide data for interruptible customer service interruptions for each of the last 5 years ending in 2015.

Response

(a) The migration of large volume customers from interruptible to firm rate classes contributed an increase of $5.9 million to distribution margin. This was primarily driven by two factors:

- As shown in part (b) of this response, there was a high number of curtailment days in the winter of 2013 and 2014 which necessitated the need for interruptible customers to acquire secondary fuel to continue their operations. Many customers expressed the intent to migrate to firm rate classes during the 2015 Budget process, and although expected migration (based upon the expressions of intention provided to the Company) was included in the forecast, actual migration occurred at a higher pace likely due to the second driver.

- As filed at EB-2012-0459, Exhibit H1, Tab 2, Schedule 3, the load factor requirement under Rate 110 was lowered from 50% to 40%. Migration occurred starting in the Fall of 2014 as interruptible customers switched from Rate 145 and Rate 170 service to Rate 110. The Company expects some migration to continue to occur, but at a much slower pace.

(b) Table 1 below illustrates the number of curtailment days for the period from 2011 to 2015 in the Central Delivery Area and the Eastern Delivery Area.

Witnesses: R. Cheung
C. Ho
R. Small

Table 1
Number of Curtailment Days

Period	CDA	EDA
October 2011 to March, 2012	0	6
October 2012 to March, 2013	6	6
October 2013 to March, 2014	21	21
October 2014 to March, 2015	3	7
October 2015 to March, 2016	2	2

Witnesses: R. Cheung
C. Ho
R. Small

IGUA INTERROGATORY #2

Interrogatory

Ref: Exhibit B, Tab 1, Schedule 3, page 2; Exhibit B, Tab 4, Schedule 2, items 2, 5 and 20.

Please provide, for each of HR and IT, the internal cost decreases and associated RCAM increases in 2015.

Response

The RCAM methodology allocates costs to Enbridge Gas Distribution ("EGD") on a fully burdened basis. A fully burdened EGD cost includes costs such as IT support, HR support, STIP, benefits, etc. When assessing the cost implications of the transfer of services from EGD to Enbridge Inc., the proper comparison is between EGD's cost decreases on a fully burdened basis and the increases in RCAM charges.

For 2015, the centralization of IT Shared Services resulted in a decrease of EGD's internal costs of $10 million versus an RCAM increase of $9.4 million.

For 2015, the centralization of HR Payroll and Benefit resulted in a decrease of EGD's internal costs of $2.5 million versus an RCAM increase of $2.6 million.

Witnesses: A. Patel
L. Stickles

IGUA INTERROGATORY #3

Interrogatory

Ref: Exhibit B, Tab 2, Schedule 4, page 2, line D.

Capital expenditures on Facilities and General Plant exceeded budget by 42% ($9.2 million). The explanation provided cites *"evolving business needs".*

(a) Is the list of causes in parentheses following the reference to "evolving business needs" exhaustive or by way of example? If by way of example, please complete the list.

(b) Please explain the *"evolving business needs"* which resulted in each of the expenditure categories referred to in response to part (a).

Response

a) The following Table 1 provides a detailed breakdown of the $9.2M related to Facilities and General Plant.

Table 1
Facilities and General Plant
2015 Actual vs. 2015 Board Approved Budget Major Variance
($millions)

		Actual Over/(Under)
	Total 2015 Variance	**9.2**
A	Fleet and Heavy Work Equipment	5.4
B	Facilities	2.1
C	Tools and Work Equipment	1.7
		9.2

Witnesses: L. Au
T. Knight

b) A and C. The explanation for the variance in lines A and C is set out in response to CME Interrogatory #2 at Exhibit I.B.EGDI.CME.2.

B. Facilities Over $2.1 Million

The 2015 overage is driven by the timing of the workspace and alterations planned for Victoria Park Centre ("VPC"). As described in EB-2012-0459, at Exhibit B2, Tab 9, Schedule 1, this project is a multi-year strategy intended to increase utilization of existing office space by both reducing the workstation/office footprint and recognizing current work styles that leverage mobility and roles that require less time within the office. The budget forecast anticipated this work to begin in 2014, however, the work forecasted was delayed. This moved additional costs into 2015. In 2015, major renovations were completed for the fifth and third floors of VPC.

Witnesses: L. Au
T. Knight

IGUA INTERROGATORY #4

Interrogatory

Ref: Exhibit B, Tab 3, Schedule 2, page 1.

Gas sales to rate 110 in 2015 were under budget by approximately 40%. Transportation revenues from rate 110 T-service customers were over budget by approximately 48%.

Please explain the drivers for each of these significant variances.

Response

Lower gas sales volumes in Rate 110 as compared to budget is driven mainly by the movement of customers from Sales class to T-Service class within Rate 110, resulting in lower than budgeted volumes for Sales customers.

Higher transportation volumes in Rate 110 as compared to budget is driven mainly by the migration of large volume customers from interruptible to firm rate classes, as discussed in the response to IGUA Interrogatory #1 at Exhibit I.B.EGDI.IGUA.1. In addition, as discussed above, movement of customers from Sales class to T-Service class within Rate 110 has also contributed to higher than budgeted volumes for T-Service customers.

Witnesses: R. Cheung
C. Ho

SEC INTERROGATORY #1

Interrogatory

Ref: [Ex.B-1-3, p.2]

Please provide details of the $5.8M sale of base pressure gas.

Response

Please refer to the response to CCC Interrogatory #1, found at Exhibit I.B.EGDI.CCC.1.

Witnesses: B. Black
R. Small

VECC INTERROGATORY #1

Interrogatory

Ref: B/T2/S1/pg.1

a) Please explain the reasons for the $5.2m in excess material and supplies over the Board approved amount.

Response

The Board approved amount is based on the forecast presented in the 2014 to 2018 Custom Incentive Regulation Rate Application (EB-2012-0459). That forecast used the 2013 Board approved (EB-2011-0354) materials and supplies budget as a starting point. Experience has shown that the materials and supplies budget presented in the 2013 proceeding was understated. Actual materials and supplies balances have exceeded Board approved in each of 2013 ($40.6M vs. $31.9M), 2014 ($35.5M vs. $32.8M), and 2015 ($38.9M vs. $33.7M). As can be seen, the 2015 variance is not materially different from the other years.

VECC INTERROGATORY #2

Interrogatory

Ref: B/T4/S2/pg.2

a) In relation to severances paid out - how many staff were made redundant in 2015?

b) Are there further severance liabilities for 2016 related to these redundancies?

Response

a) In 2015 there were regular severances as part of Enbridge Gas Distribution's regular operations, and there was a one time workforce reduction, in November 2015, across all of Enbridge including Enbridge Gas Distribution. This one time workforce reduction, which included 55 employees and 8 contract employees, was not forecasted in the IR budget and makes up the majority of the variance.

b) No there are no further severance expenses for 2016 related to these reductions. All severance expenses related to 2015 were recorded in 2015.

Witnesses: A. Patel
L. Stickles

VECC INTERROGATORY #3

Interrogatory

Ref: B/T4/S2/pg.3

a) Please detail the IT and HT decreases which offset to RCAM's $13 million increase.

Response

Please refer to the response to IGUA Interrogatory #2 at Exhibit I.B.EGDI.IGUA.2.

Witnesses: A. Patel
L. Stickles

BOARD STAFF INTERROGATORY #1

Interrogatory

Ref: C1/T1/S2 / para 2

With respect to the Unabsorbed Demand Costs Deferral Account and the 2015 UDC Management Plan included as part of the Supplementary Settlement Agreement in the 2015 rates proceeding EB-2014-0276, is it Enbridge's intention to continue the same UDC management efforts going forward? Please discuss the outlook for UDC in the coming years.

Response

Enbridge prepared and filed a UDC Management Plan, similar to 2015, as part of its 2016 Gas Supply evidence (EB-2015-0114, Exhibit D1, Tab 2, Schedule 1, Appendix A). Enbridge has also continued to file updated monthly reports with respect to the 2016 UDC Management Plan, and the potential impacts on the 2016 Unabsorbed Demand Costs Deferral Account (2016 UDCDA). As reported initially at the end of March 2016, the Company continues to forecast a zero balance in the 2016 UDCDA at the end of 2016.

While the Company hasn't concluded its gas cost budget process for 2017, early indications are that there will be no Unabsorbed Demand Costs in the 2017 fiscal year. The Company intends to include as a part of its 2017 Gas Supply evidence a "Principles Document" that will address UDC, and the commitment of the Company to provide a UDC mitigation plan in the future.

Witnesses: J. LeBlanc
D. Small

BOARD STAFF INTERROGATORY #3

Interrogatory

Ref: C1/T1/S3/ Table page 3

Staff is interested to understand how the actual results for transactional services compare to prior years. Please expand the table to show the actual transactional services results for the years 2010 to 2014.

Response

Please see attached table.

Please note that prior to 2013, Transportation Optimization was shared 75:25 between the ratepayer and the shareholder and that, prior to 2013, $8.0 million was included upfront as a reduction in rates as opposed to the $12.0 million included today.

Also, the amount generated in Transactional Services will vary from year to year dependent upon market conditions, including the value of such services in the market place.

Witnesses: J. LeBlanc
D. Small

Item #		2010 Transactional Services Revenue $ 000's	2011 Transactional Services Revenue $ 000's	2012 Transactional Services Revenue $ 000's	2013 Transactional Services Revenue $ 000's	2014 Transactional Services Revenue $ 000's	2015 Transactional Services Revenue $ 000's
1.0	Storage Optimization	8,182.8	2,755.2	4,702.6	2,433.0	1,703.4	517.4
2.0	Transportation Optimization	9,599.9	16,318.5	39,416.5	37,435.7	12,910.3	22,727.1
3.0	Transactional Services Revenue	17,782.7	19,073.7	44,119.1	39,868.8	14,613.7	23,244.6
4.0	Ratepayer Portion of Transactional Services Revenue	14,564.4	14,718.6	33,794.7	35,881.9	13,152.4	20,920.1
5.0	Less Amount Included in Rates	8,000.0	8,000.0	8,000.0	12,000.0	12,000.0	12,000.0
6.1	Transactional Services Deferral Account (TSDA) sub-total	6,564.4	6,718.6	25,794.7	23,881.9	1,152.4	8,920.1
6.2	ETT Revenue - Rider H	700.0	638.4	275.4	183.3	104.4	154.7
6.0	Transactional Services Deferral Account (TSDA) Total	7,264.5	7,356.9	26,070.1	24,065.2	1,256.7	9,074.8

BOMA INTERROGATORY #9

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 2, Attachment

Please explain the difference in the two parts of table entitled "2015 Unabsorbed Demand Cost Report". What is each of the two parts designed to show? Please provide a full response.

Response

The table entitled “2015 Unabsorbed Demand Cost Report” shown at Exhibit C, Tab 1, Schedule 2, Attachment can be viewed in two parts. The bottom half of the table beginning with the heading “Forecasted Monthly Unutilized Capacity” provides the amount in PJ’s of long haul TCPL capacity forecast to be left unutilized by the Company on a monthly basis. For example in the month of April 2015 the line labeled UDCDA shows 3.3 PJ’s of forecast unutilized contracted capacity. The section identified as “Unutilized Capacity Released” represents the capacity that the Company was able to release to third parties in accordance with its 2015 UDC Mitigation Plan. In April the Company was able to release 2.2 PJ’s under a seasonal type release (i.e., April to October), 0.8 PJ’s under an April monthly release and a total of 0.3 PJ’s released on a daily basis throughout the month of April. Therefore in April the Company was successful in releasing all of its forecast unutilized capacity.

The top half of the table provides the dollar impacts of the unutilized capacity. The line identified as “Forecasted Monetary Impacts” shows the costs of the forecast unutilized capacity. For example the line labeled UDCDA for the month of April identifies that the 3.3 PJ’s of unutilized capacity would equate to $6.6 million being charged to the 2015 UDCDA. The line item identified as “Revenue From Unutilized Capacity Released” sets out the revenues received from the third parties to whom the Company released unutilized capacity. For example in the month of April the Company received $1.2 million from seasonal type releases, $0.6 million from monthly releases and $0.1 million from daily releases. All of the revenue received from these releases was credited to the 2015 UDCDA to offset the cost of unutilized capacity. This equates to a net amount of $4.7 million being charged to the 2015 UDCDA in the month of April 2015.

Witnesses: J. LeBlanc
D. Small

CCC INTERROGATORY #4

Interrogatory

Ref: (Ex. C/T1/S7/p. 2)

Does the GDAR Account have a materiality threshold associated with it? If so, what is the threshold?

Response

The Board approved GDARIDA does not have a materiality threshold.

Witnesses: D. McIlwraith
R. Small

ENERGY PROBE INTERROGATORY #3

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 1 &
Exhibit C, Tab 2, Schedule 2

a) What is the status of the EB-2015-0267 proceeding dealing with the 2014 DSM related deferral accounts?

b) Please update Schedule 1 to reflect any changes as a result of the EB-2015-0267 proceeding that impact on the amount to be collected or the timing of the amount to be collected.

c) If necessary, please also update Exhibit C, Tab 2, Schedule 2 to reflect any changes.

Response

a) On May 26, 2016 the Board issued its EB-2015-0267 Decision and Order which approved the clearance of the 2014 DSMVA, 2014 LRAM, and 2014 DSMIDA balances as filed. The Decision and Order also ordered that clearance was to occur as a one-time adjustment to rates in Enbridge's July 1, 2016 QRAM. By letter dated May 30, 2016, Enbridge indicated that it could not accommodate clearance with the July 1, 2016 QRAM, and requested clearance to occur in October and November 2016, in conjunction with the October 1, 2016 QRAM, and the accounts to be approved as part of this proceeding (EB-2016-0142). By letter dated June 7, 2016 the Board allowed Enbridge to clear the 2014 DSM related deferral accounts within the October 1, 2016 QRAM, but stated that it would not allow interest to accrue between July 1, 2016 and October 1, 2016.

b) The summary of deferral account balances requested for clearance provided at Exhibit C, Tab, 1, Schedule 1, page 3, has been updated at Attachment #1 to this interrogatory to reflect the EB-2015-0267 required changes. The impact is a reduction in the total interest recoverable amount of approximately $22 thousand.

c) Exhibit C, Tab 2, Schedule 2 has been updated at Attachment #2 to reflect the changes of Exhibit C, Tab 1, Schedule 1.

Witnesses: J. Collier
A. Kacicnik
R. Small
B. So

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

Line No.	Account Description	Account Acronym	Col. 1 Actual at March 31, 2016 Principal ($000's)	Col. 2 Actual at March 31, 2016 Interest ($000's)	Col. 3 Forecast for clearance at October 1, 2016 Principal ($000's)	Col. 4 Forecast for clearance at October 1, 2016 Interest ($000's)	
	Non Commodity Related Accounts						
1.	Demand Side Management V/A	2014 DSMVA	352.5	5.2	352.5	6.1	1
2.	Demand Side Management V/A	2015 DSMVA	1,391.4	3.8	-	-	2
3.	Lost Revenue Adjustment Mechanism	2014 LRAM	(65.3)	(0.2)	(65.3)	(0.5)	1
4.	Demand Side Management Incentive D/A	2014 DSMIDA	7,647.2	28.0	7,647.2	49.0	1
5.	Deferred Rebate Account	2015 DRA	419.0	0.4	419.0	2.8	3
6.	Manufactured Gas Plant D/A	2016 MGPDA	537.7	35.0	-	-	4
7.	Electric Program Earnings Sharing D/A	2015 EPESDA	(59.3)	(0.2)	(59.3)	(0.8)	5
8.	Gas Distribution Access Rule Impact D/A	2015 GDARIDA	-	-	295.2	-	6
9.	Average Use True-Up V/A	2015 AUTUVA	(2,278.3)	(6.3)	(2,278.3)	(18.9)	7
10.	Earnings Sharing Mechanism Deferral Account	2015 ESMDA	(6,450.0)	(17.7)	(6,450.0)	(53.1)	8
11.	Customer Care CIS Rate Smoothing D/A	2015 CCCISRSDA	1,124.2	11.7	-	20.1	9
12.	Customer Care CIS Rate Smoothing D/A	2014 CCCISRSDA	2,927.0	21.5	-	43.1	9
13.	Customer Care CIS Rate Smoothing D/A	2013 CCCISRSDA	4,634.9	34.1	-	68.1	9
14.	Transition Impact of Accounting Changes D/A	2016 TIACDA	75,408.6	-	4,435.8	-	10
15.	Post-Retirement True-Up V/A	2015 PTUVA	(880.1)	(17.0)	(880.1)	(21.8)	11
16.	Constant Dollar Net Salvage Adjustment D/A	2016 CDNSADA	42,042.2	-	-	-	12
17.	Energy East Consultation Costs D/A	2015 EECCDA	157.5	0.7	157.5	1.3	13
18.	Greenhouse Gas Emissions Impact D/A	2016 GGEIDA	127.5	0.4	-	-	14
19.	Total non commodity Related Accounts		127,036.7	99.4	3,574.2	95.4	
	Commodity Related Accounts						
20.	Transactional Services D/A	2015 TSDA	(9,074.8)	(74.9)	(9,074.8)	(124.7)	15
21.	Storage and Transportation D/A	2015 S&TDA	4,771.4	46.0	4,771.4	72.4	15
22.	Unaccounted for Gas V/A	2015 UAFVA	1,302.9	5.2	1,302.9	12.4	16
23.	Unabsorbed Demand Cost D/A	2015 UDCDA	65,834.3	432.4	65,834.3	794.2	17
24.	Total commodity related accounts		62,833.8	408.7	62,833.8	754.3	
25.	Total Deferral and Variance Accounts		189,870.5	508.1	66,408.0	849.7	

Notes:

1. The final 2014 DSMVA, LRAM, and DSMIDA balances to be cleared are those which were approved within EB-2015-0267 Decision and Order. No interest will accrue during for the period July through September 2016.
2. Clearance of the 2015 DSMVA will be requested through a separate application at a later date.
3. DRA evidence is found at Exhibit C, Tab 1, Schedule 8.
4. Clearance of the balance that was recorded in 2015 MGPDA is not being requested at this time. As was indicated in the EB-2015-0114 proceeding, the balance in the 2015 MGPDA was transferred to the 2016 MGPDA.
5. EPESDA evidence is found at Exhibit C, Tab 1, Schedule 11.
6. The clearance amount associated with the 2015 GDARIDA is the result of a revenue requirement calculation found in evidence at Exhibit C, Tab 1, Schedule 7.
7. AUTUVA evidence is found at Exhibit C, Tab 1, Schedule 5.
8. Evidence within the B-series of exhibits provides details of Enbridge's 2015 utility results and 2015 earnings sharing calculation.
9. CCCISRSDA evidence is found at Exhibit C, Tab 1, Schedule 10.
10. TIACDA evidence is found at Exhibit C, Tab 1, Schedule 9.
11. PTUVA evidence is found at Exhibit C, Tab 1, Schedule 6.
12. Clearance of the balance that was recorded in 2015 CDNSADA is not being requested at this time. In accordance with the scope of the account that was approved in EB-2012-0459, and as was also indicated in EB-2015-0114, the balance was transferred to the 2016 CDNSADA. The cumulative balance at the end of each year will be transferred to the following year's CDNSADA. At the end of 2018, any residual balance will be requested for clearance in a post 2018 true-up.
13. EECCDA evidence is found at Exhibit C, Tab 1, Schedule 12.
14. Clearance of the balance that was recorded in 2015 GGEIDA is not being requested at this time. The 2015 balance of $80.3 thousand was transferred to the 2016 GGEIDA and clearance will be requested at a later date.
15. TSDA and S&TDA evidence is found at Exhibit C, Tab 1, Schedule 3.
16. UAFVA evidence is found at Exhibit C, Tab 1, Schedule 4.
17. UDCDA evidence is found at Exhibit C, Tab 1, Schedule 2.

UNIT RATE AND TYPE OF SERVICE: CLEARING IN OCTOBER And NOVEMBER 2016

		COL.1 TOTAL (¢/m³)	COL. 2 October Unit Rate	COL. 3 November Unit Rate
Bundled Services:				
RATE 1	- SYSTEM SALES	0.8927	0.4463	0.4463
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.9863	0.4931	0.4931
	- WESTERN T-SERVICE	0.8927	0.4463	0.4463
RATE 6	- SYSTEM SALES	0.4661	0.2331	0.2331
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.5597	0.2799	0.2799
	- WESTERN T-SERVICE	0.4661	0.2331	0.2331
RATE 9	- SYSTEM SALES	(0.6789)	(0.3394)	(0.3394)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.5853)	(0.2926)	(0.2926)
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.4984	0.2492	0.2492
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.4984	0.2492	0.2492
RATE 110	- SYSTEM SALES	(0.0508)	(0.0254)	(0.0254)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0428	0.0214	0.0214
	- WESTERN T-SERVICE	(0.0508)	(0.0254)	(0.0254)
RATE 115	- SYSTEM SALES	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0517)	(0.0259)	(0.0259)
	- WESTERN T-SERVICE	(0.1453)	(0.0727)	(0.0727)
RATE 135	- SYSTEM SALES	(0.1744)	(0.0872)	(0.0872)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0809)	(0.0404)	(0.0404)
	- WESTERN T-SERVICE	(0.1744)	(0.0872)	(0.0872)
RATE 145	- SYSTEM SALES	(1.2751)	(0.6375)	(0.6375)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(1.1815)	(0.5907)	(0.5907)
	- WESTERN T-SERVICE	(1.2751)	(0.6375)	(0.6375)
RATE 170	- SYSTEM SALES	(0.3706)	(0.1853)	(0.1853)
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.2770)	(0.1385)	(0.1385)
	- WESTERN T-SERVICE	(0.3706)	(0.1853)	(0.1853)
RATE 200	- SYSTEM SALES	0.2881	0.1440	0.1440
	- BUY/SELL	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3817	0.1908	0.1908
	- WESTERN T-SERVICE	0.0000	0.0000	0.0000
Unbundled Services:				
RATE 125	- All	(0.1707)	(0.0853)	(0.0853)
	- Customer-specific ($)	$0		
RATE 300	- All	(2.6363)	(1.3182)	(1.3182)

Determination of Balances to be Cleared
from the 2015 Deferral and Variance Accounts

ITEM NO.		COL. 1 PRINCIPAL For CLEARING ($000)	COL. 2 INTEREST ($000)	COL. 3 TOTAL For CLEARING ($000)
1.	TRANSACTIONAL SERVICES D/A	(9,074.8)	(124.7)	(9,199.5)
2.	UNACCOUNTED FOR GAS V/A	1,302.9	12.4	1,315.3
3.	STORAGE AND TRANSPORTATION D/A	4,771.4	72.4	4,843.8
4.	DEFERRED REBATE ACCOUNT	419.0	2.8	421.8
5.	DEMAND SIDE MANAGEMENT 2014	352.5	6.1	358.6
6.	LOST REVENUE ADJ MECHANISM 2014	(65.3)	(0.5)	(65.8)
7.	DEMAND SIDE MANAGEMENT INCENTIVE 2014	7,647.2	49.0	7,696.2
9.	ELECTRIC PROGRAM EARNINGS SHARING	(59.3)	(0.8)	(60.1)
10.	GAS DISTRIBUTION ACCESS RULE D/A 2015	295.2	0.0	295.2
11.	AVERAGE USE TRUE-UP V/A	(2,278.3)	(18.9)	(2,297.2)
12.	POST-RETIREMENT TRUE-UP V/A	(880.1)	(21.8)	(901.9)
13.	2015 CUSTOMER CARE CIS RATE SMOOTHING D/A		20.1	20.1
14.	2014 CUSTOMER CARE CIS RATE SMOOTHING D/A		43.1	43.1
15.	2013 CUSTOMER CARE CIS RATE SMOOTHING D/A		68.1	68.1
16.	ENERGY EAST CONSULTATIONS	157.5	1.3	158.8
17.	UNABSORBED DEMAND COST D/A	65,834.3	794.2	66,628.5
19.	TRANSITION IMPACT OF ACCT CHANGE D/A	4,435.8		4,435.8
20.	EARNINGS SHARING MECHANISM	(6,450.0)	(53.1)	(6,503.1)
21.	TOTAL	66,408.0	849.7	67,257.7

Classification and Allocation of Deferral and Variance Account Balances

ITEM NO.			COL.1 TOTAL ($000)	COL. 2 SALES AND WBT ($000)	COL. 3 TOTAL SALES ($000)	COL. 4 TOTAL DELIVERIES ($000)	COL. 5 SPACE ($000)	COL. 6 DELIVE-RABILITY ($000)	COL. 7 DISTRIBUTION REV REQ (DRR) ($000)	COL. 8 DIRECT ($000)	COL. 9 NUMBER OF CUSTOMERS ($000)	COL. 10 RATE BASE ($000)
	CLASSIFICATION											
	PGVA:											
1.1	COMMODITY		-		-							
1.2	SEASONAL PEAKING-LOAD BALANCING		-					-				
1.3	SEASONAL DISCRETIONARY-LOAD BALANCING		-				-					
1.4	TRANSPORTATION TOLLS		-	-								
1.5	CURTAILMENT REVENUE		-					-		-		
1.6	RIDER C 2009 DIRECT ALLOCATION		-							-		
1.7	INVENTORY ADJUSTMENT		-									
1.			-	-	-	-	-	-	-	-	-	-
1.	**TRANSACTIONAL SERVICES D/A**		(9,199.5)	(8,841.4)			(129.6)	(228.5)				
2.	**UNACCOUNTED FOR GAS V/A**		1,315.3			1,315.3						
3.	**STORAGE AND TRANSPORTATION D/A**		4,843.8				1,753.5	3,090.3				
4.	**DEFERRED REBATE ACCOUNT**		421.8			421.8						
5.	**DEMAND SIDE MANAGEMENT 2014**		358.6							358.6		
6.	**LOST REVENUE ADJ MECHANISM 2014**		(65.8)							(65.8)		
7.	**DEMAND SIDE MANAGEMENT INCENTIVE 2014**		7,696.2							7,696.2		
9.	**ELECTRIC PROGRAM EARNINGS SHARING**		(60.1)									(60.1)
10.	**GAS DISTRIBUTION ACCESS RULE D/A 2015**		295.2								295.2	
11.	**AVERAGE USE TRUE-UP V/A**		(2,297.2)							(2,297.2)		
12.	**POST-RETIREMENT TRUE-UP V/A**		(901.9)									(901.9)
13.	**2015 CUSTOMER CARE CIS RATE SMOOTHING D/A**		20.1								20.1	
14.	**2014 CUSTOMER CARE CIS RATE SMOOTHING D/A**		43.1								43.1	
15.	**2013 CUSTOMER CARE CIS RATE SMOOTHING D/A**		68.1								68.1	
16.	**ENERGY EAST CONSULTATIONS**		158.8	158.8		-					-	
17.	**UNABSORBED DEMAND COST D/A**		66,628.5					66,628.5				
19.	**TRANSITION IMPACT OF ACCT CHANGE D/A**		4,435.8						-			4,435.8
20.	**EARNINGS SHARING MECHANISM**		(6,503.1)						-			(6,503.1)
21.	**TOTAL**		67,257.7	(8,682.6)	-	1,737.1	1,623.9	69,490.3	-	5,691.8	426.5	(3,029.3)
	ALLOCATION											
1.1	RATE 1		44,837.7	(4,446.5)	-	729.1	782.1	38,724.8	-	10,727.1	393.1	(2,072.1)
1.2	RATE 6		24,376.8	(3,647.2)	-	730.5	756.7	29,772.8	-	(2,404.1)	33.3	(865.3)
1.3	RATE 9		(2.2)	(0.3)	-	0.0	-	0.1	-	0.2	0.0	(2.3)
1.4	RATE 100		18.5	(3.5)	-	0.5	(0.0)	22.1	-	-	0.0	(0.6)
1.5	RATE 110		45.8	(240.1)	-	97.5	28.6	278.1	-	(94.4)	0.0	(23.9)
1.6	RATE 115		(315.1)	(50.2)	-	74.7	0.0	64.5	-	(391.7)	0.0	(12.6)
1.7	RATE 125		(16.9)	-	-	-	-	-	-	8.8	-	(25.7)
1.8	RATE 135		(94.7)	(39.2)	-	10.0	-	-	-	(64.0)	0.0	(1.6)
1.9	RATE 145		(935.3)	(19.7)	-	11.3	7.1	-	-	(926.7)	0.0	(7.3)
1.10	RATE 170		(1,205.9)	(112.3)	-	57.6	25.3	-	-	(1,167.1)	0.0	(9.5)
1.11	RATE 200		549.6	(123.7)	-	25.7	24.0	628.1	-	3.0	0.0	(7.6)
1.12	RATE 300		(0.4)	-	-	-	-	-	-	0.6	-	(1.0)
1.			67,257.7	(8,682.6)	-	1,737.1	1,623.9	69,490.3	-	5,691.8	426.5	(3,029.3)
			0.0	-	-	-	-	-	-	0.0	-	-
	check allocation by service type:											
	RATE 1	-	44,837.7	(4,446.5)	-	729.1	782.1	38,724.8	-	10,727.1	393.1	(2,072.1)
	RATE 6	-	24,376.8	(3,647.2)	-	730.5	756.7	29,772.8	-	(2,404.1)	33.3	(865.3)
	RATE 9	-	(2.2)	(0.3)	-	0.0	-	0.1	-	0.2	0.0	(2.3)
	RATE 100	-	18.5	(3.5)	-	0.5	(0.0)	22.1	-	-	0.0	(0.6)
	RATE 110	-	45.8	(240.1)	-	97.5	28.6	278.1	-	(94.4)	0.0	(23.9)
	RATE 115	-	(315.1)	(50.2)	-	74.7	0.0	64.5	-	(391.7)	0.0	(12.6)
	RATE 125	-	(16.9)	-	-	-	-	-	-	8.8	-	(25.7)
	RATE 135	-	(94.7)	(39.2)	-	10.0	-	-	-	(64.0)	0.0	(1.6)
	RATE 145	-	(935.3)	(19.7)	-	11.3	7.1	-	-	(926.7)	0.0	(7.3)
	RATE 170	-	(1,205.9)	(112.3)	-	57.6	25.3	-	-	(1,167.1)	0.0	(9.5)
	RATE 200	-	549.6	(123.7)	-	25.7	24.0	628.1	-	3.0	0.0	(7.6)
	RATE 300	-	(0.4)	-	-	-	-	-	-	0.6	-	(1.0)
			67,257.7	(8,682.6)	-	1,737.1	1,623.9	69,490.3	-	5,691.8	426.5	(3,029.3)

ALLOCATION BY TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE- RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE
		($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
Bundled Services:											
RATE 1	- SYSTEM SALES	40,689.0	(4,266.3)	0.0	665.1	713.4	35,323.4	0.0	9,784.9	358.6	(1,890.1)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	2,430.4			36.0	38.6	1,909.6	0.0	529.0	19.4	(102.2)
	- WBT	1,718.3	(180.2)		28.1	30.1	1,491.7	0.0	413.2	15.1	(79.8)
RATE 6	- SYSTEM SALES	13,507.9	(2,712.3)	0.0	422.8	438.0	17,232.4	0.0	(1,391.5)	19.3	(500.8)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	6,212.6			161.9	167.8	6,600.3	0.0	(533.0)	7.4	(191.8)
	- WBT	4,656.2	(934.9)		145.7	151.0	5,940.0	0.0	(479.6)	6.6	(172.6)
RATE 9	- SYSTEM SALES	(1.9)	(0.3)	0.0	0.0	0.0	0.1	0.0	0.2	0.0	(2.0)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(0.2)			0.0	0.0	0.0	0.0	0.0	0.0	(0.3)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE 100	- SYSTEM SALES	18.0	(3.4)	0.0	0.5	(0.0)	21.5	0.0	0.0	0.0	(0.6)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	0.0			0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- WBT	0.5	(0.1)		0.0	(0.0)	0.6	0.0	0.0	0.0	(0.0)
RATE 110	- SYSTEM SALES	(21.8)	(40.1)	0.0	6.2	1.8	17.8	0.0	(6.1)	0.0	(1.5)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	176.1			60.0	17.6	171.3	0.0	(58.2)	0.0	(14.7)
	- WBT	(108.6)	(200.1)		31.2	9.2	89.0	0.0	(30.2)	0.0	(7.7)
RATE 115	- SYSTEM SALES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(237.3)			66.9	0.0	57.7	0.0	(350.7)	0.0	(11.2)
	- WBT	(77.9)	(50.2)		7.8	0.0	6.7	0.0	(41.0)	0.0	(1.3)
RATE 135	- SYSTEM SALES	(4.1)	(2.2)	0.0	0.3	0.0	0.0	0.0	(2.2)	0.0	(0.1)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(21.6)			3.9	0.0	0.0	0.0	(24.9)	0.0	(0.6)
	- WBT	(69.0)	(37.0)		5.8	0.0	0.0	0.0	(36.9)	0.0	(0.9)
RATE 145	- SYSTEM SALES	(167.1)	(12.3)	0.0	1.9	1.2	0.0	0.0	(156.7)	0.0	(1.2)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(667.4)			8.2	5.1	0.0	0.0	(675.5)	0.0	(5.3)
	- WBT	(100.8)	(7.4)		1.2	0.7	0.0	0.0	(94.5)	0.0	(0.7)
RATE 170	- SYSTEM SALES	(129.6)	(32.7)	0.0	5.1	2.2	0.0	0.0	(103.4)	0.0	(0.8)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	(761.4)			40.1	17.6	0.0	0.0	(812.5)	0.0	(6.6)
	- WBT	(314.9)	(79.5)		12.4	5.5	0.0	0.0	(251.2)	0.0	(2.0)
RATE 200	- SYSTEM SALES	380.7	(123.7)	0.0	19.3	18.0	470.5	0.0	2.3	0.0	(5.7)
	- BUY/SELL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	- T-SERVICE EXCL WBT	168.9			6.5	6.0	157.5	0.0	0.8	0.0	(1.9)
	- WBT	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unbundled Services:											
RATE 125		(16.9)	0.0	0.0	0.0	0.0	0.0	0.0	8.8	0.0	(25.7)
RATE 300		(0.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.6	0.0	(1.0)
		67,257.7	(8,682.6)	0.0	1,737.1	1,623.9	69,490.3	0.0	5,691.8	426.5	(3,029.3)

UNIT RATE AND TYPE OF SERVICE

		COL.1	COL. 2	COL. 3	COL. 4	COL. 5	COL. 6	COL. 7	COL. 8	COL. 9	COL. 10	COL. 11
		TOTAL	SALES AND WBT	TOTAL SALES	TOTAL DELIVERIES	SPACE	DELIVE-RABILITY	DISTRIBUTION REV REQ (DRR)	DIRECT	NUMBER OF CUSTOMERS	RATE BASE	NUMBER OF CUSTOMERS
		(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	(¢/m³)	($000/user)
Bundled Services:												
RATE 1	- SYSTEM SALES	0.8927	(0.0936)	0.0000	0.0146	0.0157	0.7750	0.0000	0.2147	0.0079	(0.0415)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.9863			0.0146	0.0157	0.7750	0.0000	0.2147	0.0079	(0.0415)	0.0000
	- WESTERN T-SERVICE	0.8927	(0.0936)		0.0146	0.0157	0.7750	0.0000	0.2147	0.0079	(0.0415)	0.0000
RATE 6	- SYSTEM SALES	0.4661	(0.0936)	0.0000	0.0146	0.0151	0.5947	0.0000	(0.0480)	0.0007	(0.0173)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.5597			0.0146	0.0151	0.5947	0.0000	(0.0480)	0.0007	(0.0173)	0.0000
	- WESTERN T-SERVICE	0.4661	(0.0936)		0.0146	0.0151	0.5947	0.0000	(0.0480)	0.0007	(0.0173)	0.0000
RATE 9	- SYSTEM SALES	(0.6789)	(0.0936)	0.0000	0.0146	0.0000	0.0204	0.0000	0.0711	0.0003	(0.6917)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.5853)			0.0146	0.0000	0.0204	0.0000	0.0711	0.0003	(0.6917)	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
RATE 100	- SYSTEM SALES	0.4984	(0.0936)	0.0000	0.0146	(0.0000)	0.5947	0.0000	0.0000	0.0000	(0.0173)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- WESTERN T-SERVICE	0.4984	(0.0936)		0.0146	(0.0000)	0.5947	0.0000	0.0000	0.0000	(0.0173)	0.0000
RATE 110	- SYSTEM SALES	(0.0508)	(0.0936)	0.0000	0.0146	0.0043	0.0416	0.0000	(0.0141)	0.0000	(0.0036)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.0428			0.0146	0.0043	0.0416	0.0000	(0.0141)	0.0000	(0.0036)	0.0000
	- WESTERN T-SERVICE	(0.0508)	(0.0936)		0.0146	0.0043	0.0416	0.0000	(0.0141)	0.0000	(0.0036)	0.0000
RATE 115	- SYSTEM SALES	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0517)			0.0146	0.0000	0.0126	0.0000	(0.0765)	0.0000	(0.0025)	0.0000
	- WESTERN T-SERVICE	(0.1453)	(0.0936)		0.0146	0.0000	0.0126	0.0000	(0.0765)	0.0000	(0.0025)	0.0000
RATE 135	- SYSTEM SALES	(0.1744)	(0.0936)	0.0000	0.0146	0.0000	0.0000	0.0000	(0.0932)	0.0000	(0.0023)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.0809)			0.0146	0.0000	0.0000	0.0000	(0.0932)	0.0000	(0.0023)	0.0000
	- WESTERN T-SERVICE	(0.1744)	(0.0936)		0.0146	0.0000	0.0000	0.0000	(0.0932)	0.0000	(0.0023)	0.0000
RATE 145	- SYSTEM SALES	(1.2751)	(0.0936)	0.0000	0.0146	0.0091	0.0000	0.0000	(1.1958)	0.0000	(0.0094)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(1.1815)			0.0146	0.0091	0.0000	0.0000	(1.1958)	0.0000	(0.0094)	0.0000
	- WESTERN T-SERVICE	(1.2751)	(0.0936)		0.0146	0.0091	0.0000	0.0000	(1.1958)	0.0000	(0.0094)	0.0000
RATE 170	- SYSTEM SALES	(0.3706)	(0.0936)	0.0000	0.0146	0.0064	0.0000	0.0000	(0.2956)	0.0000	(0.0024)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	(0.2770)			0.0146	0.0064	0.0000	0.0000	(0.2956)	0.0000	(0.0024)	0.0000
	- WESTERN T-SERVICE	(0.3706)	(0.0936)		0.0146	0.0064	0.0000	0.0000	(0.2956)	0.0000	(0.0024)	0.0000
RATE 200	- SYSTEM SALES	0.2881	(0.0936)	0.0000	0.0146	0.0136	0.3560	0.0000	0.0017	0.0000	(0.0043)	0.0000
	- BUY/SELL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	- ONTARIO T-SERVICE	0.3817			0.0146	0.0136	0.3560	0.0000	0.0017	0.0000	(0.0043)	0.0000
	- WESTERN T-SERVICE	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Unbundled Services:												
RATE 125	- All	(0.1707)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0882	0.0000	(0.2589)	0.0000
	- Customer-specific **											0.0000
RATE 300	- All	(2.6363)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.7384	0.0000	(6.3747)	0.0000
	- Customer-specific **											

Notes:
* Unit Rates derived based on 2015 actual volumes

Enbridge Gas Distribution Inc.
2015 Deferral and Variance Account Clearing

Bill Adjustment in October and November 2016 for Typical Customers

Item No.	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Unit Rates			Bill Adjustment		
	GENERAL SERVICE	Annual Volume m3	Sales cents/m3	Ontario TS cents/m3	Western TS cents/m3	Sales Customers $	Ontario TS Customers $	Western TS Customers $
1.1	**RATE 1 RESIDENTIAL**							
1.2	Heating & Water Heating	2,400	0.4463	0.4931	0.4463	10.7	11.8	10.7
2.1	**RATE 6 COMMERCIAL**							
2.2	General Use	43,285	0.2331	0.2799	0.2331	101	121	101
	CONTRACT SERVICE							
3.1	**RATE 100**							
3.2	Industrial - small size	339,188	0.2492	0.0000	0.0000	845	-	-
4.1	**RATE 110**							
4.2	Industrial - small size, 50% LF	598,568	(0.0254)	0.0214	(0.0254)	(152)	128	(152)
4.5	Industrial - avg. size, 75% LF	9,976,121	(0.0254)	0.0214	(0.0254)	(2,534)	2,135	(2,534)
5.1	**RATE 115**							
5.2	Industrial - small size, 80% LF	4,471,609	0.0000	(0.0259)	(0.0727)	-	(1,157)	(3,249)
6.1	**RATE 135**							
6.2	Industrial - Seasonal Firm	598,567	(0.0872)	(0.0404)	(0.0872)	(522)	(242)	(522)
7.1	**RATE 145**							
7.2	Commercial - avg. size	598,568	(0.6375)	(0.5907)	(0.6375)	(3,816)	(3,536)	(3,816)
8.1	**RATE 170**							
8.2	Industrial - avg. size, 75% LF	9,976,121	(0.1853)	(0.1385)	(0.1853)	(18,487)	(13,818)	(18,487)

Notes:
Col. 6 = Col. 2 x Col. 3
Col. 7 = Col. 2 x Col. 4
Col. 8 = Col. 2 x Col. 5

FRPO INTERROGATORY #10

Interrogatory

REF: Exhibit C, Tab 1, Schedule 2 and Exhibit D, Tab 4, Schedule 1, Page 21

Preamble: Schedule 2 states "*The value of the released capacity in 2015 equated to approximately 23.8% of associated cost ($20.5 million divided by $86.3 million) compared to 2014 when the Company received $5.3 million for released capacity valued at $31.7 million or approximately 16.7%*."

Page 21 states: "*Provided at Appendix 8.7 is a copy of the updated monthly breakdown of the forecasted 2016 UDCDA that the Company reported at the end of March 2016 which now indicates zero UDC in 2016".*

Please provide a comparison on a per unit (PJ) basis between 2014 and 2015.

a) Has the Enbridge employed a similar approach in 2016?
    i) If not, how has Enbridge evolved their approach from 2015?

Response

In 2014, the applicable TCPL toll was approximately $1.57/GJ which when applied to the 20.2 PJ's of unutilized capacity translated to $31.7 million in potential UDC costs. However, the Company was able to, on average, receive $0.26/GJ for the capacity it did release to third parties. These releases generated $5.3 million which was offset against the cost of unutilized capacity.

In 2015, the TCPL toll increased to approximately $1.98/GJ which when applied to the unutilized capacity of 43.6 PJ's amounts to $86.3 million in potential UDC costs. However, the Company was able to, on average, receive approximately $0.47/GJ for the capacity it released to third parties which generated $20.5 million. These releases were used as an offset against the cost of the unutilized capacity.

Enbridge committed to providing an update to its 2016 UDC Mitigation Plan near the end of the winter season of the year in question. Enbridge provided an update as part of its March 31, 2016 report which indicated that it was forecasting full utilization of contracted long haul capacity for utility purposes throughout the summer of 2016. Consequently the Company will not need to implement a UDC mitigation plan for 2016.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #11

Interrogatory

REF: Exhibit C, Tab 1, Schedule 2 and Exhibit D, Tab 4, Schedule 1, Page 21

Preamble: Schedule 2 states "*The value of the released capacity in 2015 equated to approximately 23.8% of associated cost ($20.5 million divided by $86.3 million) compared to 2014 when the Company received $5.3 million for released capacity valued at $31.7 million or approximately 16.7%*."

Page 21 states: "*Provided at Appendix 8.7 is a copy of the updated monthly breakdown of the forecasted 2016 UDCDA that the Company reported at the end of March 2016 which now indicates zero UDC in 2016".*

Based upon this type of forecasting of asset and asset right utilization, does the company see opportunities for other applications of this approach to mitigate ratepayer risk?

a) Please explain the positive or negative response

Response

The development of the UDC Mitigation Plan was in response to unique circumstances. While contracting for 1 year firm long haul transportation with TCPL was the cheaper alternative than contracting for STFT service as was the practice in the past, it still resulted in a significant UDC cost increase to be paid by the ratepayer. The UDC Mitigation plan, which was developed in conjunction with intervenor input, is viewed by the Company as a transparent way to provide intervenors insight into a short term solution for dealing with UDC. As the Company contracts for more short haul transportation services Enbridge anticipates lower overall gas costs for the ratepayers of Ontario, and absent any extreme changes in cost there will be no need for a UDC mitigation plan going forward.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #12

Interrogatory

REF: Exhibit C, Tab 1, Schedule 3

Preamble: "*The balance in the 2015 S&TDA that the Company is proposing to collect from customers is $4.77 million plus interest.*

Please provide the cost of service and market based detail to support this charge.

a) Please show how incremental transportation revenues are taken into account in this calculation.
   i) If not accounted for, please explain the rationale.

Response

As stated at Exhibit C, Tab 1, Schedule 3, page 1 of 3, the purpose of the S&TDA is to capture the difference between forecast and actual costs for third party storage and transmission services (i.e. charges under Union Gas M12 rates). It is unclear as to what is meant by "incremental transportation revenues". However, the Company can confirm that any monies received from Union Gas as a part of Union's deferral account disposition are included as an offset to the S&TDA.

The primary driver for the amount in the 2015 S&TDA is related to the timing of the 2015 Gas Cost forecast. When preparing the 2015 Gas Cost forecast, the Company used Union tolls that were in place at that time which included a Dawn to Parkway toll for M12 Service of $2.420/GJ/month. Subsequent to the preparation of the budget, the M12 toll increased to $2.604/GJ/month, effective January 1, 2015. The difference in the assumed toll versus the effective toll when applied to the 2015 contracted transportation capacity of 1,957,173 equates to approximately $360,000 per month in additional charges from Union relative to what was assumed in the Gas Cost budget. This accounts for more than $4.3 million of the $4.77 million balance in the 2015 S&TDA.

Witnesses: J. LeBlanc
D. Small

FRPO INTERROGATORY #13

Interrogatory

REF: Exhibit C, Tab 1, Schedule 4

Please provide the monthly conversion factors for volumetric (m3) to energy equivalent (GJ) that Enbridge used in 2015 to calculate Direct Purchase Banked Gas Accounts.

a) In tabular format, please show the total monthly volumes used and the resulting energy that was accounted for Direct Purchase customers in reconciling upstream energy deliveries from Union Gas and TCPL.

Response

Exhibit C, Tab 1, Schedule 4 is a discussion on Unaccounted For Gas ("UAF") and has no bearing on Direct Purchase Banked Gas Accounts.

Without acknowledging the relevance of the question, in an effort to be helpful the Company has the following response.

For purposes of determining a Direct Purchase customer's Banked Gas Account ("BGA") balance, the deliveries for a particular pool, which are in GJ's, are converted using 37.69 MJ/m^3 in accordance with the Rate Handbook and entered into EnTRAC. The billed volume, or consumption, for the end-use customers in that particular pool is then uploaded from the billing system to EnTRAC. The difference between the delivery volume and the billed volume is used to calculate the BGA balance for a particular pool.

The table provides the monthly Direct Purchase deliveries received in GJ's and the applicable volume recorded in EnTRAC.

Witnesses: R. Cheung
C. Ho
D. Small
A. Welburn

Direct Purchase Deliveries

2015	GJ's	10^3m^3
January	13,199,355	350,212.5
February	12,317,029	326,802.0
March	13,512,385	358,517.9
April	13,631,483	361,677.7
May	15,055,177	399,451.6
June	14,207,326	376,956.1
July	14,060,609	373,063.5
August	13,996,091	371,351.7
September	13,719,228	364,005.8
October	13,149,755	348,896.5
November	12,802,998	339,728.0
December	13,277,377	352,311.4

Witnesses: R. Cheung
C. Ho
D. Small
A. Welburn

FRPO INTERROGATORY #14

Interrogatory

REF: Exhibit C, Tab 1, Schedule 5, page 1

Preamble: "*Higher weather-normalized average use is primarily attributable to lower actual natural gas prices in 2015 than was forecast. Lower gas prices have been shown to increase consumption for both Rate 1 and Rate 6 customers".*

Please provide the evidence that lower gas prices result in higher weather-normalized average use.

a) If data demonstrating this effect is available over multiple consecutive years, please provide the history.

Response

Average use is forecast for Rate 1 and Rate 6 customers using a Board-approved methodology that relies on econometric regression models that estimate the historical relationship of average use and various driver variables. This forecasting methodology has been in place since the 2001 Budget year utilizing data from 1985. Models have been stable year after year, supporting the consistent impact that key drivers of gas price and economic conditions play in the determination of future demand.

Results from the Average Use econometric models are included as part of the annual Rates application pre-filed evidence. Regression models used to forecast 2015 average use were shown in EB-2014-0276 at Exhibit C2, Tab 1, Schedule 3, starting on page 11. Most Rate 1 and Rate 6 models include the real price of natural gas as an explanatory variable and in each case, the relationship (represented by a negative value of the coefficient) confirms that as price increases (decreases), average use consumption decreases (increases), keeping all other factors constant. This relationship between gas prices and average use is consistent, maintained, and statistically significant with each additional year of actual values.

Data isolating the pure impact of the level of natural gas prices on consumption are not available, hence the need to rely on econometric model results to quantify the relationship of average use consumption and the factors that influence the level of that consumption.

Witnesses: R. Cheung
C. Ho
H. Sayyan
M. Suarez

FRPO INTERROGATORY #15

Interrogatory

REF: Exhibit C, Tab 1, Schedule 5, Appendix A, column 10

Given the variety of tiers in Rates 1 and 6 and seasonal monthly consumption, how is the unit rate in column 10 determined as representative for the purposes of this adjustment.

a) Please show an example using Rate 6

Response

The unit rates depicted in Exhibit C, Tab 1, Schedule 5, Appendix A, Column 10 represent the average variable delivery unit rates. The derivation of the AUTVA dollar amount (refund or charge) balance is completed at year end once final actual annual volumes are available; therefore seasonal monthly profiles are not taken into consideration for this calculation. In other words, just like the Company's rates are designed/set on an annual basis, so is the derivation of the AUTVA dollar balance.

The rationale and clarification for using these unit rates was also explained in response to FRPO Interrogatory #1 in EB-2014-0195 (Exhibit I, Tab 4, Schedule 1). That interrogatory response has been reproduced below in a form that is updated to reflect EB-2016-0142 references and calculations.

As explained in Exhibit C, Tab 1, Schedule 5, page 1, paragraph 4, the purpose of the Average Use True-up Variance Account ("AUTUVA") is to record the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rates classes (Rate 1 and 6) embedded in the volume forecast that underpins Rates 1 and 6, and the actual weather normalized average use experienced during the year. Impacts due to changes in the cost of gas are accounted for through the Company's gas cost related variance/deferral accounts (i.e., PGVA, UAF). Gas costs are removed so the Company and ratepayers are kept whole when determining the AUTVA balance and no double counting of gas costs occurs.

The unit rates depicted in Column 10 of Exhibit C, Tab 1, Schedule 5, Appendix A represent the variable delivery unit rate (exclusive of gas costs). The use of this rate is necessary to determine the revenue impact, exclusive of gas costs. These unit rates when applied to the volume variance form the AUTVA balance to be either collected or refunded to ratepayers. In order to develop the variable delivery unit rate, adjustments

Witnesses: R. Cheung
J. Collier
C. Ho
A. Kacicnik

must be made to the Rate 1 and 6 Board approved delivery rates to remove the impact of gas costs. As explained in the rate design evidence in EB-2012-0459, Exhibit H1, Tab 1, Schedule 1, page 5, paragraph 12, storage and unaccounted for gas costs are recovered through the Company's delivery rates. The distribution costs are recovered primarily through the Company's delivery rates, however, some distribution related costs are recovered from the commodity and load balancing rates.

The Rate 1 and 6 blocked delivery rates have some gas costs related expenses such as Lost and Unaccounted for Gas and Union Storage costs. Conversely, some of the Company's operating expenses such as Bad Debt commodity, system gas administration and return on gas in inventory are recovered through the gas supply and load balancing charges.

To determine the variable delivery unit rate, the Company takes the Total Delivery Revenues (fixed and variable) for the rate class and subtracts the gas costs recovered in the delivery charge and then adds back the rate classes allocated cost of operating expenses recovered in the gas supply and load balancing charges. This yields a Total Delivery Revenue exclusive of gas costs.

To determine the variable delivery unit rate, the amount of fixed customer charge revenue is subtracted which results in the remaining delivery revenue to be recovered from the variable delivery unit rate. The variable delivery unit rate is determined by taking the variable delivery revenues divided by the forecast delivery volumes. The derivation of the Rate 1 and 6 unit rates (based on the EB-2014-0276 Rate Order) are depicted below.

	Rate 1	Rate 6
Total Delivery Revenues ($ Million)	764.363	344.042
Less: allocated gas cost related expenses in delivery charge ($ Million)	-75.912	-64.571
Add: allocated EGD expenses recover in other charges ($ Million)	15.7	14.8
Total Rate Class Delivery Only Revenues ($ Million)	704.131	294.222
Less: Revenue recovered from fixed customer charges ($ Million)	-464.144	-138.289
Total Variable Delivery Only Revenue ($ Million)	239.987	155.933
Divide: Delivery Volumes 106m3	4675.743	4695.021
Variable Delivery Unit Rates ($/m3)	0.0513	0.0332
(i.e. Unit rate of the Revenue Impacts Exclusive of Gas Costs)		

Witnesses: R. Cheung
J. Collier
C. Ho
A. Kacicnik

IGUA INTERROGATORY #5

Interrogatory

Ref: Exhibit C, Tab 1, Schedule 10.

The evidence indicates that the Customer Care CIS Rate Smoothing Deferral Account (CCCISRSDA) interest was to be cleared annually. In this application, EGD is seeking clearance of interest for the years 2013, 2014 and 2015.

(a) Please explain why the 2013 and 2014 interest balances were not proposed for clearing in earlier applications.

(b) Please provide the interest that has accrued on the 2013 interest balance since October 2014.

(c) Please provide the interest that has accrued on the 2014 interest balance since October, 2015.

Response

a) The approved EB-2011-0226 (Customer Care and CIS Costs for 2013 to 2018) Settlement Agreement specified that Enbridge would be entitled to collect interest, at a fixed annual rate of 1.47%, on the balances in the CCCISRSDAs, and that interest would be cleared annually at the same time as other Deferral and Variance Account clearings.

   In accordance with that Settlement Agreement, as part of the 2014 ESM and Deferral Clearance proceeding EB-2015-0122, Enbridge requested and received approval to clear interest which had accrued on the 2013 and 2014 CCCISRSDA principal balances through to September 30, 2015. As was indicated in Exhibit C, Tab 1, Schedule 10 of that proceeding, the Company had not requested the clearance of accrued interest on the 2013 CCCISRSDA as part of the 2013 Clearance of Deferral Accounts proceeding, EB-2014-0195. Therefore the interest approved for clearance as part of the EB-2015-0122 proceeding, reflected interest accrued during 2013, 2014, and through to September 30, 2015 in relation to the 2013 CCCISRSDA, and interest accrued during 2014 and through to September 30, 2015 in relation to the 2014 CCCISRSDA.

Witnesses: D. McIlwraith
R. Small

Within this application, the Company is now seeking clearance of interest accrued on the 2013 and 2014 CCCISRSDA principal balances between October 1, 2015 and September 30, 2016 (the annual amount since interest was last cleared), and interest accrued on the 2015 CCCISRSDA during its establishment throughout 2015, through to September 30, 2016.

b) No interest has been accrued on a 2013 interest balance. Interest is only calculated on the principal balance recorded in the 2013 CCCISRSDA. As indicated in part a) above, within this application the Company is seeking clearance of interest accrued on the 2013 CCCISRSDA principal balance between October 1, 2015 and September 30, 2016, reflecting the annual interest accrued since it was last cleared ($4,634.9K * 1.47% = $68.1K).

c) No interest has been accrued on a 2014 interest balance. Interest is only calculated on the principal balance recorded in the 2014 CCCISRSDA. As indicated in part a) above, within this application the Company is seeking clearance of interest accrued on the 2014 CCCISRSDA principal balance between October 1, 2015 and September 30, 2016 reflecting the annual interest accrued since it was last cleared ($2,927.0K * 1.47% = $43.0K).

Witnesses: D. McIlwraith
R. Small

IGUA INTERROGATORY #6

Interrogatory

Ref: Exhibit C, Tab 2, Schedule 1.

The evidence proposes that the 2015 deferral account balances will be cleared by way of application of a unit rate to actual 2015 volumes for each customer, the product of this calculation to be collected from customers through October and November bills.

Other than the spreading of the resulting charges over two months, please confirm that this approach to recovery of approved deferral account balances is the same approach as approved in previous years.

Response

Yes, other than the spreading of the clearance over two months, the approach to recovery of approved deferral account balances is the same approach as approved in previous years.

Witnesses: J. Collier
A. Kacicnik
B. So

SEC INTERROGATORY #2

Interrogatory

Ref: [Ex.C-1-2]

Please provide details regarding Enbridge's actual performance compared to the UDC Management Plan agreed to in the EB-2014-0276 Settlement Agreement.

Response

Details of the 2015 UDC Mitigation Plan and the associated outcomes of that plan can be found at Exhibit C1, Tab 2, Schedule 2, pages 1 to 3, plus Attachment. Further detail can be found in the responses to Exhibit I.C.EGDI.BOMA.9, Exhibit I.C.EGDI.FRPO.10 and Exhibit I.C.EGDI.STAFF.1.

Witnesses: J. LeBlanc
D. Small

VECC INTERROGATORY #4

Interrogatory

Ref: C/T1/S1/pg.3

a) Please show the relationship (calculation) as between the interest balances shown for the CCCISRSDA accounts (lines 11-12) actual at March 31, 2016 as compared to the amounts shown for clearance at October 1, 2016.

Response

As specified within the EB-2011-0226 approved Settlement Agreement, Enbridge is entitled to collect interest at a fixed annual rate of 1.47%, on the balances in the CCCISRSDAs. As a result, the forecast October 1, 2016 interest balances requested for clearance, on each of the 2013, 2014, and 2015 CCCISRSDAs, reflects an incremental six months of interest, at a rate of 1.47%, as compared to the March 31, 2016 actual interest balances. Detailed calculations for each account are shown below. The interest amounts shown below may be slightly different from what is set out in Exhibit C, Tab 1, Schedule 1, because of rounding to show numbers in 000's rather than as whole numbers.

2013 CCCISRSDA

Principal: $4,634,908

Interest rate: 1.47%

Monthly interest: $4,634,908 * 1.47% / 12 months = $5,678

Interest at March 31, 2016: $34,067

Interest at October 1, 2016: $34,067 + (5,678 * 6 months) = $68,135

<u>2014 CCCISRSDA</u>

Principal: $2,927,041

Interest rate: 1.47%

Monthly interest: $2,927,041* 1.47% / 12 months = $3,586

Interest at March 31, 2016: $21,514

Interest at October 1, 2016: $21,514 + (3,586 * 6 months) = $43,030

<u>2015 CCCISRSDA</u>

Principal: $1,124,203

Interest rate: 1.47%

Monthly interest: $1,124,203* 1.47% / 12 months = $1,377

Interest at March 31, 2016: $11,705

Interest at October 1, 2016: $11,705 + (1,377 * 6 months) = $19,967

VECC INTERROGATORY #5

Interrogatory

Ref: C/T1/S11/pg.11 & C/T1/S1/pg.3

a) The description of this deferral account discusses an amount of ($0.1) million recorded in the 2015 EPESDA for clearance. The table at Exhibit C, Tab 1, Schedule 1, shows principle amounts of($59.3) million and interest of (0.8) for this account. Please reconcile.

Response

The Company is seeking approval to clear ($59.3) thousand in relation to the 2015 EPESDA account, plus associated interest of ($0.8) thousand, as included within the summary of amounts to be cleared provided at page 3, Columns 3 and 4, of Exhibit C, Tab 1, Schedule 1. The evidence provided in support of the clearance of the 2015 EPESDA at Exhibit C, Tab 1, Schedule 11, references an amount of ($0.1) million, which is the ($59.3) thousand referenced in Exhibit C, Tab 1, Schedule 1, rounded to millions of dollars.

Witness: E. Reimer

BOARD STAFF INTERROGATORY #2

Interrogatory

Ref: D/T4/S1

Please discuss whether the UDC Management Plan is included in the 2015-2016 Gas Supply Memorandum.

Response

Please see the response to Board Staff Interrogatory #1 at Exhibit I.C.EGDI.STAFF.1

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #10

Interrogatory

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

(a) Please confirm that none of the cost overruns, estimated now to be $922 million, less $687 million, or $235 million, has been closed to rate base or otherwise included in 2015 rates or 2014 rates.

(b) Please provide the estimated cost to complete the project in 2016.

(c) Please indicate when intervenors and the Board will have the opportunity to review the prudency of these costs.

Response

(a) Confirmed.

(b) Construction risks are diminishing as final clean up and restoration work is currently progressing well. As a result, the forecast cost at completion is currently trending to be between $900M and $922M.

(c) The full costs of the GTA Project will be open to review in a future proceeding. During 2016, the Company continues to close out the GTA Project activities (final clean up and site restoration). As explained in response to CME Interrogatory 3(a) at Exhibit I.D.EGDI.CME.3, the Company will be filing its Post Construction Financial Report by July 1, 2017. It should be noted that for ratemaking purposes, the rate base amounts for the GTA Project are fixed at approximately $687 million until the end of the Custom IR term.

Witness: S. Dodd

BOMA INTERROGATORY #11

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 3, Page 1, Paragraph 4

The WAMS project will apparently cost about $10 million more than forecast costs, upon completion. Please indicate in what proceeding ratepayers will have an opportunity to review the prudency of these costs.

Response

Please see response to FRPO Interrogatory #2 at Exhibit I.B.EGDI.FRPO.2.

Witnesses: W. Akkermans
B. Misra

BOMA INTERROGATORY #12

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 6, Pages 1-2; Exhibit D, Tab 3, Schedule 1, Asset Management Section

(a) Is the UMS study still on track to be completed this summer? In which month?

(b) When will EGD make the study available to intervenors?

(c) Please explain the function of the RIVA software.

Response

a) The UMS study is still on track to be completed by September 2016. Further updates will be completed in 2017 to incorporate 2016 information.

b) Enbridge will report on the status of the Asset Management system at the 2017 Stakeholder Day, and in the 2016 ESM proceeding. If relevant, this may include a high-level overview of the results of the UMS study.

c) RIVA (now PowerPlan Asset Management Planning Suite) is a modelling tool that enables decision support relating to specific assets and allows the optimization of risk, performance, and cost when developing a spend portfolio. The function of the tool was discussed during the stakeholder day presentations.

BOMA INTERROGATORY #13

Interrogatory

Ref: Exhibit D, Tab 2, Schedule 1, Page 6 – Productivity Improvements

(a) Please explain how "decentralized workload planning" is the result of reorganization of the company along functional lines of accountability, rather than the traditional Regional structure.

(b) Please explain what Alternative Locate Agreements are, and how they contribute to increased efficiency. Is it a pooling of staff with other utilities or agencies?

Response

(a) The reorganization along functional lines of accountability created a more consistent and efficient process-driven organization. Members of the centralized Work Management Centre ("WMC") tasked with ordering work dependencies such as permits, locates and traffic plans were decentralized and embedded within each of the operating depots. This had the positive effect of increasing the level of collaboration between downstream work execution and upstream dependencies. For example, WMC clerks now participate in the daily work management processes and interact directly with Field Managers, Supervisors and Field Workers. This allows for work to be scheduled quickly, changes to be addressed immediately, and minimizes downtime for outside workers. Further, third party utility locate requests can be matched more easily with pre-inspection requirements, allowing for quicker resolution of errors and omissions. WMC clerks and supervisors no longer travel between a centralized location and field depots for meetings and workload planning sessions, eliminating time wasted in transit. Finally, direct communication allows WMC clerks and field workers to prioritize changes to the schedule, enabling better management of unscheduled overtime on planned work.

(b) An Alternative Locate Agreement ("ALA") is a contractual agreement between Enbridge and an excavator. This agreement allows the excavator to proceed with specific pre-defined methods of low risk excavation specified in the agreement without requiring the natural gas infrastructure to be field located. This allows Enbridge and the Company's Locate Service Providers to assign resources to requests that require full field locates, rather than focusing on low risk digs. Without ALAs, more field resources would be required to complete locates for these low risk excavations.

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #14

Interrogatory

Ref: Ibid, Page 7

(a) Please correlate the discussion at paragraph 19, and the savings listed on page 4, Table 3, of $5.7 million for "FTEs".

(b) What are the offsetting severance costs referred to in paragraph 19?

(c) Are the bad debt savings, discussed at paragraph 20, the result of company efforts, and to what extent?

(d) What was the reduction of O&M due to capitalization of back-office type O&M function? Does this not just shift dollars from O&M to capital? Please explain fully. Please explain the relationship, if any, between those savings and the increase in Capitalized Departmental Labour savings ($11.6 million - $3.2 million = $8.4 million), in Table 4 at page 9. Please explain fully.

Response

(a) On page 4, Table 3, the $5.7 million for FTEs represents the 2015 Embedded O&M reductions that were eliminated from the O&M budgets filed in the Custom IR as guaranteed savings to the ratepayers. Paragraph 19 describes 2015 FTE savings results of $8.2 million, which exceeds the embedded reduction. Table 4 on page 9 shows the embedded reduction of $5.7M, along with the achieved gross reduction of $8.2M.

(b) The offsetting severance costs totaled $13.3 million. Severance costs were excluded to represent the total reduction in gross salaries and wages in 2015 resulting from the management of FTEs. Please see the response to CCC Interrogatory #3 at Exhibit I.B.EGDI.CCC.3 for more details on the severance costs.

(c) The Company has managed to improve the overall performance of collections driving reductions in bad debt expense. Continued improvements in the economy and overall employment play a contributing role in customer payment patterns but the Company has been diligent in its efforts to improve performance in the following areas:

- Management of collection agencies. This was a function repatriated in the last contract renegotiation with Accenture and has led to improved recovery of receivables across all customer groups. Process changes include a new tier where receivables are assigned to collection agencies earlier in the aging process.

- Transfers of receivables from inactive to active accounts. The Company has improved management of accounts when processing customer moves to ensure 'finalized' accounts with outstanding balances are matched to newly opened accounts.

- New incentive mechanism with Accenture. Another aspect of the renegotiated contract with Accenture includes a financial incentive to improve key operating metrics for overall receivables management. This has led to further operational improvements in the Company's account management processes driving increased payments and lower bad debt.

- New payment alternatives. As credit card issuers in Canada have introduced new programs, the Company has successfully added credit card payment options for customers under a user-pay model. This allows customers a new payment option while still maintaining the company's overall collection costs.

(d) The capitalization of O&M back office salaries refers to Administrative and General overheads ("A&G") capitalized as part of the total cost of a capital asset. This includes HR Costs (e.g., Benefits), Information technology (e.g., IT department operating costs) and Other A&G (e.g., Finance). In 2015, total reductions of O&M due to capitalization of back office functions totaled $41.4 million, as compared to the forecast of $37.7 million (Exhibit B, Tab 4, Schedule 2). Capitalization of costs associated with capital projects is the appropriate way to reflect the costs and should not be considered as a shift of O&M costs to capital.

A&G capitalized is unrelated to Capitalized Departmental Labour savings and should be viewed separately. As described in the evidence referenced at Exhibit D, Tab 2, Schedule 1, page 7, paragraph 19, "Departmental Labour Costs ("DLC") that were capitalized relate to back-office type functions such as planning, drafting, pipeline inspections, field operations and records management within Operations and Engineering departments and as such are not impacted by the delays in Capital Projects".

There are embedded savings of $3.2 million in the DLC reflected within the 2015 capital budget. Actual DLC costs were $8.4 million below the capital budget, meaning that Enbridge Gas Distribution achieved a total of $11.6 million in savings.

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #15

Interrogatory

Ref: Ibid, Page 8

Please explain how longer term construction contracts stabilize and reduce costs. Please provide an example of how this would work.

Response

Long-term construction contracts provide Enbridge's construction contractors predictable workload and cash flow security which in turn allows them to offer Enbridge construction cost certainty (construction pricing) for a number of years. Additionally, the Company's construction contractors with long-term contracts obtain benefits such as reduced financing costs, economies of scale, increased buying power and improved workload planning. This results in reduced labour and administrative costs due to the long term arrangements that they pass on to Enbridge.

An example is the contractor's workforce planning. When Enbridge is able to provide the contractor a work plan numerous years in advance, the contractor is able to hire an appropriate number of workers, resulting in less crew downtime. These cost efficiencies can be passed on to Enbridge.

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #16

Interrogatory

Ref: Ibid, Page 11, Paragraph 29

(a) Please break down the $1.6 million in O&M and $0.6 million in capital into the major components.

(b) Please give an example or two of "hiring of specific skill sets to offset outside services".

Response

(a)

Labour Optimization Initiatives	
	($M)
O&M	
Absorption of work	1.0
Reallocation of Tasks	0.6
Total O&M	1.6
Capital	
Absorption of work	0.1
Reallocation of Tasks	0.5
Total Capital	0.6

(b) One example of hiring of specific skill sets to offset outside services is the hiring of skilled training developers in the Technical Training group. With these resources, the Company has the ability to develop new courses and update existing courses without contracting outside services. The training developers have converted courses that are delivered in person to web-based courses which not only provide for training flexibility but also reduce significant travel expenses incurred by employees for attending instructor-led in-person training.

Witnesses: L. Lawler
M. Yan

A second initiative is the hiring of a paralegal in the Claims Department to assist with commencing and defending Small Claims actions on behalf of Enbridge. Prior to the hiring of the paralegal, all litigation matters including Small Claims were outsourced to an external law firm. The paralegal works under the supervision of the Law Department, and has handled over 80 claims since 2014.

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #17

Interrogatory

Ref: Ibid, Paragraphs 30 and 32

(a) EGD estimates savings of $5.7 million in O&M and $2.0 million in capital from process optimization but the examples provided added up to only $2.4 million (O&M or capital?) in 2015. Please provide the other initiatives and savings these other initiatives generated that made up the remainder of the $7.7 million in estimated savings.

(b) What does EGD estimate the 2016 savings from e-bill would be based on experience to date in 2016?

(c) Other than the successful carbon monoxide response initiative, can you provide other examples of initiatives driven by policy changes or improvements, and the savings from these other initiatives?

Response

(a)

O&M	**($M)**	**Sample Key Initiatives**
Customer-related process changes	4.0	e-bill initiative resulting in postage and print cost savings.
Employee-related process changes	1.5	Departmental Training and Development budgets were centralized to maximize pricing.
Other	0.1	Rationalization of patents resulting in reduced Legal and application fees.
Total O&M	5.7	
Capital		
Operations-related	1.0	Co-ordination of work between Asset Renewal & Improvement (AR&I) and Corrosion Department to reduce Operations costs.
Supply Chain-related	0.1	Management negotiated lowered freight charges.
Information Technology-related	0.2	Management negotiated lowered project costs from IT vendors.
Engineering-related	0.8	Improved quality of Gate/Feeder Station drawings resulting in decreased vendor costs.
Total Capital	2.0	

Witnesses: L. Lawler
M. Yan

(b) Enbridge Gas Distribution estimates the 2016 savings from e-bill to be $700,000 in 2016 for cumulative savings of $2.3 million from 2014 to 2016.

(c) One example of productivity driven by policy change or improvement is the Company's shift to D800 series meters. The D800 series meters are replacing meters that required sampling every seven (7) years. The new meters have a seal life of twenty (20) years. Further, the meters are less expensive than the alternate meters and maintenance costs will be lower due to the longer sampling frequency. In 2015, a total of $660,000 in capital savings is attributed to purchasing D800 series compared to what would have been spent on alternate meters.

Another example is in the area of subscription materials. The Economics team relied on annual subscriptions from various data providers as part of their forecasting activities. Over the past couple of years, they have streamlined the frequency of their forecasts and identified the key areas of focus, allowing them to switch to a variable subscription with fees that are driven by user access. This has enabled the Company to save $12,000 in O&M costs in 2015 alone.

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #18

Interrogatory

Ref: Exhibit D, Tab 2, Schedule 1, Page 12, Paragraph 31

Please explain in more detail what the "parallel testing environment" is, and how it was able to achieve estimated savings of $2.1 million in O&M and $3.2 million in capital. If the parallel testing environment initiative was only one of several initiatives that accounted for those savings, please provide details of the other IT initiatives and the savings achieved by each.

Response

A parallel testing environment or landscape is a collection of servers, databases, and application software required for the CIS application. For example, there is a production landscape, a pre-production landscape, and a development landscape that are all utilized by CIS.

For the SAP Upgrade Project, the team determined that utilizing the existing CIS hardware to act as a secondary CIS landscape dedicated to production support would satisfy business requirements at reduced cost relative to what had been budgeted. The team captured these savings as a productivity initiative.

This initiative resulted in capital savings of $250,000 due to eliminating the need to purchase new servers.

This IT improvement is only one of the initiatives in the area of materials, equipment, and space rationalization. The table on the following page provides details of the breakdown of O&M and capital savings for each factor where IT initiatives fall within the “equipment” category.

Witnesses: L. Lawler
M. Yan

Other Factor Optimization Initiatives		
O&M	**($M)**	**Sample Key Initiatives**
Material Rationalization	0.4	Printing Savings from replacement of hard copy documents with electronic training materials and; electronic welcome materials for new customers.
Space Rationalization	1.2	Consolidation of available space to reduce leasing costs.
Equipment (including IT)	0.3	Software maintenance rationalization resulting in discontinued software usage.
Other	0.3	Continued use and improved efficiency of the Turbo Expander results in increased electricity savings.
Total O&M	2.1	
Capital		
Material Rationalization	0.2	Reduced capital costs by purchasing well equipment to avoid rental costs.
Equipment (including IT)	3.1	Utilization of new inspection technology to reduce capital costs on pipeline modifications for inspections; and creation of Parallel Testing Environment while utilizing existing CIS hardware.
Total Capital	3.2	

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #19

Interrogatory

Ref: Ibid, Page 17

Please comment on the variability of a Grade 1(A) Leak in 2013, 2014, and 2015. What are Grade 1(A) Leaks? Please discuss.

Response

A Class “A” leak is a leak which represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous. The identification of Class “A” leaks can be generated from Enbridge Leak Survey programs, routine maintenance work or the general public or first responders calling the Company to inform of the smell of gas. In each case, Enbridge crews will investigate, and based on findings, confirm whether the leak should be classified as an “A” leak. There are numerous Leak Survey Programs which Enbridge conducts annually. The frequency of these programs varies based on the location, pressure and material type. The variability of annual “A” leaks is driven primarily from the asset mix being leak surveyed for any given year, as such some variability is seen in the results from 2013 to 2015.

Witnesses: L. Lawler
M. Yan

BOMA INTERROGATORY #20

Interrogatory

Ref: Exhibit D, Tab 3, Schedule 1, Pages 59-60

(a) Does EGD have any sort of award or recognition system for employees that suggest new productivity initiatives? If not, why not? Please discuss fully.

(b) Please provide the articles and President's Dispatches highlighting productivity improvement successes.

(c) Please list the "100 reported initiatives".

Response

(a) Enbridge Gas Distribution promotes its core values and has identified productivity as a business priority. Enbridge Gas Distribution does not have an award or recognition system for employees specifically for suggesting productivity initiatives. The Company instead has a recognition system that allows people leaders and peers to recognize employees who have demonstrated the core values of safety, integrity, and respect, and have gone above and beyond what is expected from their day-to-day work. To the extent that productivity initiatives are identified and carried out by employees, the method of recognition is ultimately at the leader's discretion.

(b) Please see attachment Exhibit I.D.EGDI.BOMA.20 for an example of a recent article highlighting a recent productivity improvement success.

(c) Enbridge Gas Distribution identified over one hundred initiatives. The list below includes initiatives that were categorized and reported as Embedded or Incremental, and also initiatives that do not have estimated savings or are still under development. Initiatives that were duplicates were excluded.

Witnesses: L. Lawler
M. Yan

2015 Productivity Initiatives*	
*Please note that not all initiatives captured were reported, nor resulted in savings.	
	# of Initiatives
O&M	
Labour Optimization	
FTE Reductions (non-exhaustive)	11
Absorption of work	20
Reallocation of Tasks	4
Consolidation of Training function	1
Process Optimization	
Customer-Related	35
Employee-Related	6
Operations-Related	18
Other	1
Materials Rationalization	4
Space Rationalization	2
Equipment Rationalization	8
Policy Changes & Improvements	16
Total O&M Initiatives	126
Capital	
Labour Optimization	
Absorption of work	1
Reallocation of Tasks	1
Process Optimization	
Operations-related	9
Supply Chain-related	8
Information Technology-related	3
Engineering-related	3
Material Rationalization	1
Equipment (including IT)	4
Policy Changes & Improvements	2
Total Capital Initiatives	32
Total Non-Duplicate Initiatives	**158**

Witnesses: L. Lawler
M. Yan

Productivity Pays Off in Finance

Group challenges the status quo and improves work-life balance

It's almost the end of the month and employees in Enbridge Gas Distribution's Financial Reporting Group are expecting to spend the weekend at home. That may not seem newsworthy but it's a big change compared to how things used to be – and it's a change that was inspired by productivity.

The group's role ties them to a demanding schedule: At the end of every month, they need to ensure they have accounted for all of the company's expenses and revenues. For example, if a vendor has done $1 million of work for us but the invoice has yet to be received, the group would be looking at different systems and reports to identify and record the outstanding amounts.

They get the inputs from various departments and must turn them around quickly so that other groups downstream of them can do their work. The team often had to work late nights and weekends to ensure those deadlines weren't missed. It's just always been that way.

Then, on the path to improved productivity, the group took a step back: "We asked ourselves, as a collective – Accounts Payable, Operations Solutions, Financial Reporting, IT—is there a better way?" said Sam Fallis, Lead, Finance Capital. "We could see that the reports we were relying on had some key information, and we realized we might also be able to pull out other information for different functions."

With a little detective work, lots of knowledge sharing and some big picture thinking, they were able to consolidate entries from 32 sources down to 20. Work that used to be executed by 10 different people is now managed by only four, which freed the others to focus on value-added tasks.

"No one liked the status quo, so the change was easy to implement," said Sam. "Before, we felt rushed and sometimes people would panic and get upset. Now things are calm and systematic, and we can actually go for lunch."

The change paid off in quality as well: giving fewer people a broader view means more consistent practices and less variability in the data.

"This was an employee-led change and demonstrates great creativity and leadership by all involved," said Andrew Mandyam, Director, Finance and Regulatory Affairs, EGD. "The team improved the quality of their work and also their quality of life. It's productivity at its best."

Published: February 24, 2016

BOMA INTERROGATORY #21

Interrogatory

Ref: Exhibit D, Tab 4, Schedule 1, Page 7 – Gas Supply Plan Memorandum

Please explain, in layman's terms, the sentence:

"These weather conditions are statistically determined using a 1 in 5 recurrence interval based on a log-normal distribution";

and,

"A more conservative level of risk (i.e. a longer recurrence interval) will result in a gas supply plan…".

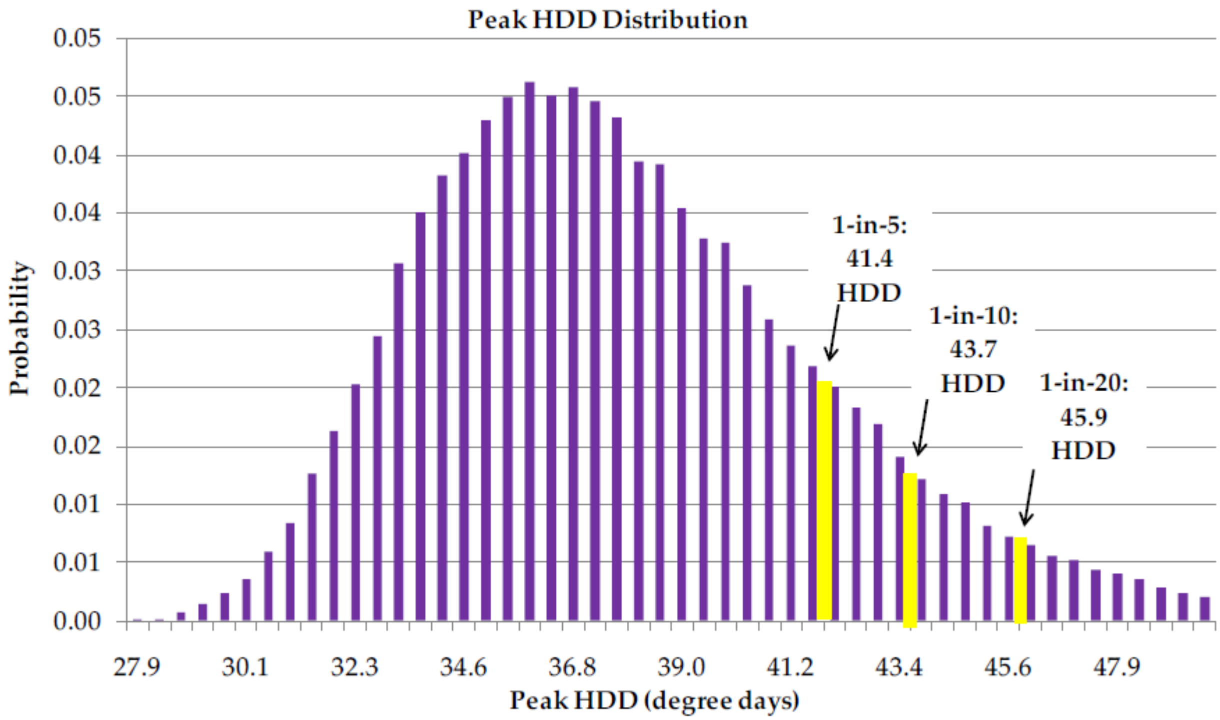
Response

The weather conditions in the first reference relate to the 18 multi-peaks that are included in the Design Criteria that have previously been approved by the Board. The 18 multi-peaks represent the coldest temperatures that are expected to occur over the winter season of the planning period.

In order to determine the temperatures associated with the multi-peaks, a review of historical and mathematically modeled temperatures has been conducted. When the temperatures were plotted on a graph, they represented a "bell curve" distribution or shape. From a statistical perspective, there are a number of "bell curve" distributions that have different characteristics. With respect to the multi-peak weather conditions, the "bell curve" shape that most closely represented the temperature data was a "log-normal" distribution. An example of the log-normal distribution for the Central Region is provided below[1].

[1] EB-2011-0354, Exhibit D2, Tab 4, Schedule 2, page 10, Figure 2-D

Witnesses: D. Small
A. Welburn



The type of distribution is important so that the data can be represented and analyzed mathematically. Part of the mathematical analysis looked at the recurrence interval. In layman's terms, this means that the analysis looked at the likelihood that certain temperatures would be reached in any given year. For example, a 1 in 5 recurrence of achieving 41.4 heating degree days means that the 41.5 heating degree days would be achieved 1 time every 5 years. Said differently, there is a 1 out of 5, or 20%, probability of 41.5 heating degree days being achieved in any year.

By increasing the recurrence interval, you extend the duration over which an event will occur. This is similar to saying that you reduce the likelihood of an event occurring. For example, if the recurrence interval is increased from 1 in 5 to 1 in 10, then the likelihood, of the event occurring has decreased from a probability in any year from 20% to 10% respectively which increases the associated weather condition. This is an important concept when it comes to gas supply planning since the likelihood of an event occurring is similar to saying the risk of an event occurring. If the event is a weather temperature that exceeds the planned peak heating degree day, then there will likely be insufficient natural gas supply, transportation, and/or storage in the gas supply plan and incremental natural gas supply will have to be purchased at a time when demand is extremely high which tends to lead to higher costs.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #22

Interrogatory

Ref: Ibid, Page 9 – Renewable Gas Supply

The Ontario government's Climate Change Action Plan (pages 28 and 68), published on June 9, 2016, placed emphasis on "greening the gas supply" through the introduction of renewable content for natural gas commencing in 2017. It allocated $60-$100 million to the task. How will EGD incorporate these requirements into their natural gas supply plan, and what implications will it have for the costs to ratepayers?

Response

The Company is encouraged by the Ontario government's messaging with respect to lowering the carbon content in the natural gas distribution system. It is clear that the vast and resilient natural gas infrastructure already in place in Ontario needs to continue to be leveraged, and "greening the gas supply" is a significant step in the right direction. Enbridge is currently evaluating how best to incorporate Renewable Natural Gas ("RNG") as part of its gas supply portfolio. At this time it is too early to estimate the cost impact to ratepayers as it will depend on several factors, including: volume of RNG supply available, proximity of RNG supply to the franchise area, comparable price of natural gas at hubs utilized by Enbridge, and the price of carbon allowances in the upcoming Ontario cap and trade market. As more certainty around these issues materializes, the Company will be able to provide potential ratepayer impacts on a project-by-project basis.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #23

Interrogatory

Ref: Ibid, Canadian Gas Supply

In its 2016 Stakeholder Presentation (at page 26, attached), Union Gas noted that during the winter peaks in gas prices in New York, the amount of Marcellus/Utica gas coming into Ontario declined. Why does EGD think that happened, and what are its implications for EGD's security of supply with its steadily increasing reliance on gas imports from the US?

Response

Absent the specific data or assumptions underpinning the Union Gas graph, it is difficult to speculate on materials that have been created and presented by other parties.
The graph would appear to indicate that the natural gas supply being received at Kirkwall is not firm. Since demand for natural gas supply is inversely related to changes in temperature, the graph suggests that natural gas supply received at Kirkwall during periods of low demand is being diverted to other markets (presumably in the New York region) when demand increases and there is more competition for a finite supply of natural gas. This is indicative of a supply source with limited liquidity.

The Company has addressed its concerns over security of supply from Niagara and Chippawa by contracting for firm natural gas supply at these import points on a seasonal and annual basis to ensure that the supply is available even during periods of low temperatures/high demand in the New York region. The supply procured at Niagara and Chippawa is then delivered directly to the Enbridge Parkway CDA using firm transportation capacity on the TransCanada PipeLines Limited Mainline. Enbridge does not transport its Niagara and Chippawa supply through Kirkwall unless it is intended to be injected into storage facilities in and around Dawn.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #24

Interrogatory

Ref: Ibid, Page 19, Figure 12 – Supply Portfolio Diversification/Niagara Gas

Please explain the increase in GJ per day at Niagara in 2018 relative to 2015. What transportation contracts will be used to bring Niagara gas to EGD's franchise, over and above the 200,000 GJ per day contract on TCPL's Domestic Line to Parkway EGD? What contracts will be acquired on Union Gas or TCPL to move the additional gas from Kirkwall to EGD franchise? Does EGD intend to purchase at Marcellus/Utica field gate, eg. Dominion South, or at the border? What is the timeframe to implement the acquisition of additional supplies at or through Niagara/Chippewa?

Response

The variance in the natural gas supply budgeted for 2015 relative to 2018 is directly related to when the transportation capacity was contracted for relative to budget reporting period. More specifically, the firm transportation capacity from Niagara/Chippawa to the Enbridge Parkway CDA included a contract start date of November 1, 2015 and as a result was only budgeted to flow for the last two months of the 2015 budget period (i.e., November and December). In 2018, the transportation capacity from Niagara/Chippawa was in service at the beginning of the budget period and was budgeted to flow for the full 12 months.

The only transportation capacity that the Company has contracted for from Niagara/Chippawa is the 200,000 GJ per day to the Enbridge Parkway CDA.
The Company does not require any transportation capacity from Kirkwall as a result of the natural gas supply purchases from Niagara/Chippawa. The natural gas supply purchased at Niagara/Chippawa will be transported directly to the Enbridge Parkway CDA which connects with the Company's distribution system.

The Niagara/Chippawa supplies are currently, and forecasted to be, acquired at the Niagara/Chippawa receipt point.

As discussed above, no Niagara/Chippawa supplies above the 200,000 GJ per day are required.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #25

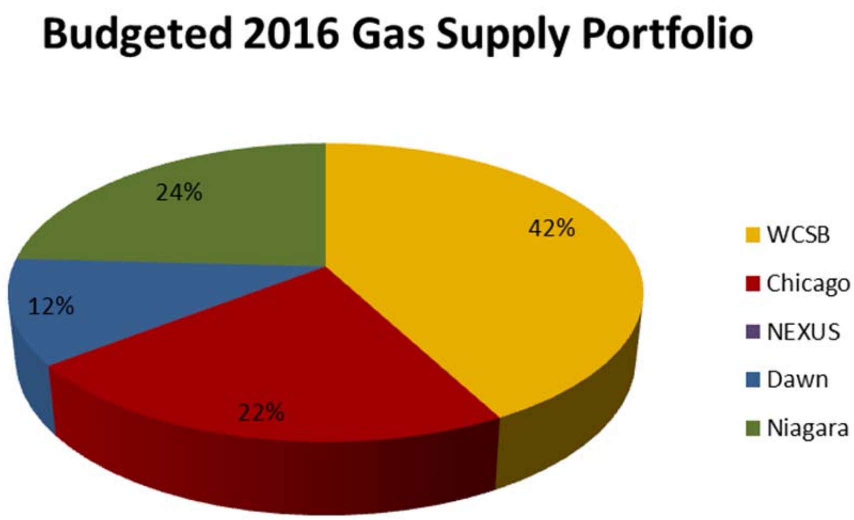
Interrogatory

Ref: Ibid, Page 19

Please provide a pie chart, similar to the one provided for 2015 and 2018, for 2016. Please provide the amounts purchased in GJs per day as a percentage of peak day supply, and separately in PJ per year as a percentage of forecast annual consumption.

Response

The requested pie chart is provided below.



The request is unclear with respect to which year the second and third part of this request is referring to. Since the first request was related to 2016, the requested data has been provided for 2016. It should be noted that the supply portfolio information provided in the pie charts do not directly correspond with the data tables provided below since the pie charts reflect purchases by the Company and do not include curtailment or natural gas supply received from direct purchase customers or storage.

Witnesses: D. Small
A. Welburn

2016 Peak Day Supply

	GJ	% of Total
WCSB	339,428	8.5%
Chicago	184,635	4.6%
NEXUS	-	0.0%
Dawn	558,900	13.9%
Niagara	200,000	5.0%
Curtailment	123,263	3.1%
Direct Purchase	425,948	10.6%
Storage	2,176,658	54.3%
Total	4,008,832	100.0%

2016 Annual Supply

	GJ	% of Total
WCSB	127,894,676	29.1%
Chicago	67,580,070	15.4%
NEXUS	-	0.0%
Dawn	39,757,485	9.0%
Niagara	73,199,999	16.6%
Curtailment[1]	123,263	0.0%
Direct Purchase	136,865,597	31.1%
Storage	(5,367,810)	-1.2%
Total	440,053,279	100.0%

[1]Assumed one day of curtailment

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #26

Interrogatory

Ref: Ibid, Page 20

Please state the months that are included in the "winter season of the 2016 fiscal year".

Response

For planning purposes the winter season begins on November 1, 2015 and ends on March 31, 2016.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #27

Interrogatory

Ref: Ibid, Page 25, Paragraph 6.4

(a) Please explain why EGD decided to rely on delivered supply or peaking services to meet any forecasted 2019 design day supply deficiency.

(b) Does EGD expect any 2019 design day deficiency? In approximately what amount?

(c) What does EGD consider to be an appropriate level of reliance (percentage of portfolio) on peaking services and delivered supply in a typical year? Will the amount vary from year to year and, if so, why? Please explain fully.

(d) What would be the relative reliance on those services for CDA and EDA, and why?

Response

(a) The Company evaluates natural gas supply options based on the principles of reliability, diversity, flexibility, and cost. Although delivered supply and peaking services are not as reliable as contracted firm transportation capacity, they are cost competitive and maintain a level of supply diversity and provide flexible contract terms when compared to the capacity offered in the 2018 New Capacity Open Season which required a 15 year term commitment.

(b) A design day sufficiency/deficiency is measured by comparing peak day demand (less curtailment) against peak day supply, which includes supplies contracted for on long haul Firm Transportation ("FT"), short haul FT, Storage Transportation Service, Union M12, Ontario T-Service deliveries to the franchise area, delivered service, and peaking service.[1] Forecasting a 2019 design day deficiency at this time would be misleading, as demand and supply conditions will change. However, the Company is satisfied that, if a deficiency should exist, it will be met with a combination of delivered supply and peaking services.

(c) The current level of peaking services and delivered supply provides a reasonable balance of reliability, diversity, flexibility, and cost to the Company's gas supply plan

[1] For an example of a test year sufficiency/deficiency calculation, see EB-2015-0114 (the 2016 Rate Application), at Exhibit D1, Tab 2, Schedule 6

Witnesses: D. Small
A. Welburn

as discussed above. The volume of peaking services and delivered supply will be evaluated each year in the context of the Company's gas supply planning principles and will be adjusted where appropriate to ensure that a reasonable balance of these principles is maintained.

The amount of peaking services and delivered supply is expected to vary from year to year. This is in large part due to the different planning horizons for firm transportation compared to peaking services and delivered supply. Firm transportation commitments must be evaluated and executed at least two years in advance of their effective date. The gas supply plan for that period of time would not have been developed yet, so an estimated level of forecasted peak day demand is used. When the gas supply plan for that period of time is being developed, the contracted firm transportation capacity is taken into consideration and the forecasted peak day demand is updated which will impact the level of supply sufficiency/deficiency. Any supply deficiency will typically be addressed through peaking services and delivered supply since the contracting horizon for these services are much more flexible.

The relative amount of peaking services and delivered supply that is contracted for to the CDA and EDA will largely depend on the availability of these services and market conditions. For example, peaking services are typically provided by parties who have contracted for firm transportation capacity to Iroquois which can be diverted upstream to the CDA and EDA for a limited number of occurrences. Since the EDA is much closer to Iroquois than the CDA, it is typically more cost effective to utilize peaking services in the EDA since the diversion is not as far upstream. Delivered supply is more akin to a baseload service and as a result is typically provided by parties that have contracted for firm transportation to the respective delivery area. Although there are limited parties other than the Company that have contracted for firm transportation to the EDA, there is firm transportation to the CDA that has been contracted by other parties who can provide delivered services. As a result, delivered services are currently utilized more in the CDA than the EDA.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #28

Interrogatory

Ref: Ibid, Page 26

Please explain Figure 13 and the preceding paragraph in somewhat more detail, in particular the sentence:

"Preliminary analysis indicates that 16 Bcf of incremental storage would be required to maintain a similar level of risk assumed in the peak day demand forecasting".

Response

Storage is a cost effective and reliable way to manage variances in annual supply and seasonal demand. In the summer, gas deliveries via the upstream pipelines to the Enbridge franchise areas exceed customer demand, allowing for excess supply to be injected into the storage facilities that the Company owns or leases from storage providers. Conversely, during the winter season, franchise demand exceeds incoming supply, and this supply deficiency is made up for primarily with storage withdrawals. Storage helps lower gas supply costs by utilizing annual transportation contracts at a higher load factor and enabling supply to be procured at more cost effective times of the year. Storage gas also provides the Company a reliable and flexible source of supply.

In EB-2014-0276 (the 2015 Rate Case), the Ontario Energy Board approved changes to the Company's storage deliverability targets, extending the maximum deliverability maintained by the Company to the end of February, and extending the maximum March deliverability to the end of March. In order to meet the new deliverability targets, the Company's gas supply plan has been altered by increasing winter supply purchases made early in the winter season to offset storage withdrawals, and maintaining higher storage balances later into the winter. If Enbridge were to acquire additional storage, it could be used to shift those increased winter supply purchases to more cost effective times of the year, and help to mitigate commodity price volatility associated with cold winter weather.

Figure 13 and the quote referenced in this interrogatory refer to a preliminary analysis Enbridge performed in order to estimate the amount of additional storage the Company would require in order to achieve varying levels of winter period demand related to different design criteria (or recurrence intervals). It is important to distinguish between the recurrence intervals listed in Figure 13 and those used in "design day" discussions such as in Section 5.1 (Page 20 of the memorandum). With respect to design day,

Witnesses: D. Small
A. Welburn

recurrence intervals refer to the likelihood of peak day having higher degree days than design, whereas the recurrence intervals in Figure 13 refer to degree days over the entire winter period. For example, a 1 in 5 recurrence interval in Figure 13 implies there is a 20% likelihood there will be greater than 3,207 heating degree days over the winter period. The reason the analysis is focused on the entire winter period instead of the peak day coverage is because the acquisition of incremental storage would benefit ratepayers by reducing the amount of supply that would need to be purchased in the winter season to maintain the new storage deliverability targets, resulting in a lower cost source of supply throughout the winter, and not just on peak day.

In Column 4 of Figure 13, incremental storage requirements are listed under varying winter recurrence intervals. The 16 Bcf quoted in the interrogatory is the result of applying a similar methodology used in the Company's peak day analysis to the entire winter period.

Witnesses: D. Small
A. Welburn

BOMA INTERROGATORY #29

Interrogatory

Ref: Ibid, Page 32

Please provide a landed cost analysis for 2016 which compares the cost of gas delivered to the EGD franchise from the various sources of gas and through various transportation routes (the latter as displayed at Page 32 of 35). The costs should show separately both the commodity costs and the transportation and storage costs. The analysis should be in the format used by Union and EGD in recent cases, and shows all assumptions, eg. currency, NYMEX price or Dawn price, other key prices. Each component of the supply chain should be shown separately and then aggregated. Where gas is purchased in a particular supply basin, eg. Marcellus, Utica, Panhandle field zone, it should be identified as such, and both US and Canadian pipeline tolls separately identified.

Response

The transportation paths identified in Budget Peak Day Demand analysis from the above reference have been included in the attached analysis. Storage costs have not been included since there is no storage cost typically associated with the transportation of natural gas supply.

The inputs used in the landed cost analysis are consistent with those used in the Company's EB-2015-0114 Rate Application for 2016.

Witnesses: D. Small
A. Welburn

Attachment BOMA.29-A

Landed Cost Analysis for Enbridge CDA

Summary of 2016 Landed Cost Analysis (C$/GJ)

Service: Path	Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-CDA	Empress	5.417	5.407	5.334	5.108	5.069	5.059	5.026	5.060	5.088	5.232	5.314	5.509	**5.219**
FT: Chippawa-to-CDA	Niagara	3.978	4.050	4.041	3.464	3.459	3.492	3.532	3.542	3.534	3.570	3.868	4.057	**3.716**
FT: Niagara Falls-to-CDA	Niagara	3.976	4.047	4.039	3.462	3.456	3.490	3.530	3.539	3.532	3.567	3.866	4.054	**3.713**
FT: Dawn-to-CDA	Dawn	4.567	4.635	4.641	4.081	3.982	4.050	4.219	4.119	4.039	4.134	4.363	4.640	**4.289**
M12: Dawn-to-CDA	Dawn	4.303	4.358	4.352	3.796	3.690	3.762	3.946	3.834	3.751	3.855	4.098	4.376	**4.010**
M12: Dawn-to-Parkway → FT SN: Parkway-to-CDA	Dawn	4.509	4.572	4.569	4.005	3.900	3.969	4.149	4.038	3.956	4.063	4.300	4.579	**4.217**
M12: Dawn-to-Parkway → STS: CDA	Dawn	4.502	4.565	4.562	3.998	3.893	3.961	4.141	4.031	3.948	4.055	4.293	4.571	**4.210**

Commodity Prices ($C/GJ)

Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
Dawn	4.170	4.227	4.224	3.679	3.583	3.658	3.842	3.734	3.651	3.743	3.978	4.249	**3.895**
Empress	3.239	3.235	3.173	2.985	2.948	2.973	2.974	2.973	2.980	3.097	3.198	3.352	**3.094**
Niagara	3.701	3.772	3.764	3.187	3.182	3.215	3.255	3.264	3.257	3.293	3.591	3.780	**3.438**

Foreign Exchange (C$/US$)

Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
US$/C$	1.221	1.222	1.222	1.222	1.222	1.223	1.223	1.223	1.223	1.223	1.223	1.223	**1.223**

Demand Charge (C$/GJ)

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-CDA	1.851	1.851	1.851	1.851	1.851	1.851	1.851	1.851	1.851	1.851	1.851	1.851	**1.851**
FT: Chippawa-to-CDA	0.267	0.267	0.267	0.267	0.267	0.267	0.267	0.267	0.267	0.267	0.267	0.267	**0.267**
FT: Niagara Falls-to-CDA	0.265	0.265	0.265	0.265	0.265	0.265	0.265	0.265	0.265	0.265	0.265	0.265	**0.265**
FT: Dawn-to-CDA	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359	0.359	**0.359**
FT SN: Parkway-to-CDA	0.198	0.198	0.198	0.198	0.198	0.198	0.198	0.198	0.198	0.198	0.198	0.198	**0.198**
STS: CDA	0.190	0.190	0.190	0.190	0.190	0.190	0.190	0.190	0.190	0.190	0.190	0.190	**0.190**
M12: Dawn-to-CDA	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	**0.086**

Abandonment Charge (C$/GJ)

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-CDA	0.147	0.147	0.147	0.147	0.147	0.147	0.147	0.147	0.147	0.147	0.147	0.147	**0.147**
FT: Chippawa-to-CDA	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	**0.010**
FT: Niagara Falls-to-CDA	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	**0.010**
FT: Dawn-to-CDA	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	0.016	**0.016**
FT SN: Parkway-to-CDA	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	**0.004**
STS: CDA	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	**0.005**
M12: Dawn-to-CDA	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**

Fuel Ratio

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-CDA	5.550%	5.390%	5.150%	4.210%	4.180%	2.950%	1.840%	3.000%	3.700%	4.400%	3.690%	4.740%	**4.07%**
FT: Chippawa-to-CDA	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
FT: Niagara Falls-to-CDA	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
FT: Dawn-to-CDA	0.530%	0.770%	1.010%	0.740%	0.670%	0.470%	0.040%	0.290%	0.360%	0.450%	0.250%	0.380%	**0.50%**
FT SN: Parkway-to-CDA	0.110%	0.270%	0.350%	0.190%	0.210%	0.120%	0.000%	0.070%	0.080%	0.130%	0.000%	0.020%	**0.13%**
STS: CDA	0.110%	0.270%	0.350%	0.190%	0.210%	0.120%	0.000%	0.070%	0.080%	0.130%	0.000%	0.020%	**0.13%**
M12: Dawn-to-CDA	1.131%	1.074%	1.003%	0.850%	0.603%	0.501%	0.487%	0.388%	0.383%	0.729%	0.870%	0.981%	**0.75%**

Witnesses: D. Small
A. Welburn

Attachment BOMA.29-B

Landed Cost Analysis for Enbridge EDA

Summary of 2016 Landed Cost Analysis (C$/GJ)

Service: Path	Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-EDA	Empress	5.487	5.476	5.402	5.175	5.137	5.125	5.092	5.127	5.155	5.300	5.381	5.578	**5.286**
FT: Dawn-to-EDA	Dawn	4.925	4.991	5.001	4.433	4.327	4.399	4.555	4.461	4.384	4.483	4.710	4.994	**4.639**
M12: Dawn-to-Parkway → STS: EDA	Dawn	4.852	4.918	4.928	4.352	4.236	4.303	4.466	4.365	4.285	4.396	4.630	4.918	**4.554**
M12: Dawn-to-Kirkwall → STS: EDA	Dawn	4.827	4.893	4.902	4.327	4.214	4.280	4.443	4.342	4.263	4.372	4.606	4.893	**4.530**

Commodity Prices ($C/GJ)

Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
Dawn	4.170	4.227	4.224	3.679	3.583	3.658	3.842	3.734	3.651	3.743	3.978	4.249	**3.895**
Empress	3.239	3.235	3.173	2.985	2.948	2.973	2.974	2.973	2.980	3.097	3.198	3.352	**3.094**

Foreign Exchange (C$/US$)

Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
US$/C$	1.221	1.222	1.222	1.222	1.222	1.223	1.223	1.223	1.223	1.223	1.223	1.223	**1.223**

Demand Charge (C$/GJ)

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-EDA	1.910	1.910	1.910	1.910	1.910	1.910	1.910	1.910	1.910	1.910	1.910	1.910	**1.910**
FT: Dawn-to-EDA	0.666	0.666	0.666	0.666	0.666	0.666	0.666	0.666	0.666	0.666	0.666	0.666	**0.666**
STS: EDA	0.489	0.489	0.489	0.489	0.489	0.489	0.489	0.489	0.489	0.489	0.489	0.489	**0.489**
M12: Dawn-to-Parkway	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	0.086	**0.086**
M12: Dawn-to-Kirkwall	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	0.072	**0.072**

Abandonment Charge (C$/GJ)

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-EDA	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	0.152	**0.152**
FT: Dawn-to-EDA	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	**0.036**
STS: EDA	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	0.024	**0.024**
M12: Dawn-to-Parkway	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**
M12: Dawn-to-Kirkwall	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	**0.000**

Fuel Ratio

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-EDA	5.740%	5.560%	5.290%	4.330%	4.310%	3.030%	1.910%	3.100%	3.820%	4.550%	3.820%	4.900%	**4.20%**
FT: Dawn-to-EDA	1.290%	1.470%	1.790%	1.430%	1.200%	1.090%	0.310%	0.700%	0.860%	1.050%	0.770%	1.040%	**1.08%**
STS: EDA	0.850%	1.070%	1.450%	1.140%	0.890%	0.730%	0.160%	0.470%	0.570%	0.710%	0.470%	0.660%	**0.76%**
M12: Dawn-to-Parkway	1.131%	1.074%	1.003%	0.850%	0.603%	0.501%	0.487%	0.388%	0.383%	0.729%	0.870%	0.981%	**0.75%**
M12: Dawn-to-Kirkwall	0.857%	0.808%	0.725%	0.537%	0.365%	0.268%	0.255%	0.156%	0.156%	0.457%	0.613%	0.722%	**0.49%**

Witnesses: D. Small
A. Welburn

Attachment BOMA.29-C

Landed Cost Analysis for Iroquois

Summary of 2016 Landed Cost Analysis (C$/GJ)

Service: Path	Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-Iroquois	Empress	5.508	5.497	5.422	5.195	5.157	5.144	5.111	5.146	5.175	5.320	5.402	5.599	**5.306**
FT: Dawn-to-Iroquois	Dawn	4.902	4.969	4.979	4.410	4.305	4.377	4.534	4.439	4.362	4.461	4.688	4.972	**4.617**

Commodity Prices ($C/GJ)

Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
Dawn	4.170	4.227	4.224	3.679	3.583	3.658	3.842	3.734	3.651	3.743	3.978	4.249	**3.895**
Empress	3.239	3.235	3.173	2.985	2.948	2.973	2.974	2.973	2.980	3.097	3.198	3.352	**3.094**

Foreign Exchange (C$/US$)

Pricing Point	January	February	March	April	May	June	July	August	September	October	November	December	Average
US$/C$	1.221	1.222	1.222	1.222	1.222	1.223	1.223	1.223	1.223	1.223	1.223	1.223	**1.223**

Demand Charge (C$/GJ)

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-Iroquois	1.922	1.922	1.922	1.922	1.922	1.922	1.922	1.922	1.922	1.922	1.922	1.922	**1.922**
FT: Dawn-to-Iroquois	0.640	0.640	0.640	0.640	0.640	0.640	0.640	0.640	0.640	0.640	0.640	0.640	**0.640**

Abandonment Charge (C$/GJ)

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-Iroquois	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	0.153	**0.153**
FT: Dawn-to-Iroquois	0.034	0.034	0.034	0.034	0.034	0.034	0.034	0.034	0.034	0.034	0.034	0.034	**0.034**

Fuel Ratio

Service: Path	January	February	March	April	May	June	July	August	September	October	November	December	Average
FT: Empress-to-Iroquois	5.970%	5.790%	5.510%	4.550%	4.530%	3.230%	2.110%	3.310%	4.040%	4.770%	4.040%	5.130%	**4.42%**
FT: Dawn-to-Iroquois	1.410%	1.600%	1.930%	1.570%	1.340%	1.230%	0.480%	0.860%	1.010%	1.190%	0.920%	1.180%	**1.23%**

Witnesses: D. Small
A. Welburn

CME INTERROGATORY #3

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 2

EGD has provided an update on the status of the GTA project. Specifically, EGD advises that the actual 2015 costs were $551M, as compared to the forecast of $359.7M. Furthermore, EGD advises that the current approximate forecast of costs remaining to complete the project are an additional $182.4M, and that the total project costs will be $922M. At the time that the Board approved the GTA project, the total forecast project cost was $686.5M.

CME is concerned with the significant increase in total estimated project costs, and would like to better understand why the project is exceeding the original Board-approved amounts. In this regard:

(a) EGD states that the overall costs increase is driven by a number of factors including escalation of construction bid price, increased costs associated with greater construction complexity, and increased project duration due to longer permit acquisition timelines. Please provide:

- (i) a more fulsome explanation for each of these cost drivers;
- (ii) the estimated overspend associated with each of these factors; and
- (iii) if the increased costs are associated with any contract disputes (with contractors or subcontractors), please explain.

(b) EGD states that it will file further evidence about the GTA project costs within the 2019 rebasing application. Is it EGD's position that the prudence of the project costs will be subject to Board scrutiny during the 2019 rebasing application? If not, please identify the proceeding in which EGD believes the GTA project overspend will be subject to the Board's scrutiny;

(c) Please confirm that no approvals sought in this current application have an impact on the ability of interested parties to scrutinize the GTA overspend in a future proceeding. If EGD believes that any of the approvals do limit or in any way affect the ability of parties to scrutinize the cost increases associated with the GTA project, please explain.

Witness: S. Dodd

<u>Response</u>

(a) As per paragraph 1.5 of the Board's Conditions of Approval (see Appendix G to the EB-2012-0451 Decision and Order), a detailed variance explanation will be provided in Enbridge's Post Construction Financial Report, which is required to be filed within 15 months of the in-service date (by July 1, 2017 at the latest).

(b) Please see response to BOMA 10(c) at Exhibit I.D.EGDI.BOMA.10.

(c) The approvals sought in this application will have no impact on interested parties' ability to review the actual costs and timing of the GTA Project in a future proceeding.

Witness: S. Dodd

CME INTERROGATORY #4

Interrogatory

Ref: Exhibit D, Tab 2, Schedule 1, page 15 of 17

In Table 7, EGD shows that it achieved its embedded reductions target of $58.8M in 2015. EGD did so by realizing savings in embedded areas of productivity and through incremental productivity initiatives. EGD further states that the embedded reductions and incremental initiatives are expected to continue throughout the custom IR term.

CME would like to better understand the anticipated productivity enhancements that EGD anticipates it can continue to achieve in 2016 and beyond. To this end:

(a) Please provide an estimate of the embedded and incremental savings which EGD believes it can achieve for both O&M and capital for 2016, 2017 and 2018;

(b) Of the $58.9M in savings achieved in 2015, does EGD believe that the savings associated with those productivity enhancements will continue beyond the custom IR term? If EGD believes that some of the productivity enhancements will not continue beyond the IR term, please identify those enhancements, provide an estimate of the savings associated with those enhancements, and provide an explanation for why those savings are not sustainable beyond the custom IR term.

Response

(a) Based on a review of current initiatives and the combined experience from the first and second years of the Customer Incentive Regulation ("CIR") term, Enbridge Gas Distribution estimates embedded O&M productivity savings of approximately $24 million, $23 million and $22 million for 2016, 2017 and 2018, respectively. As discussed in Exhibit D, Tab 2, Schedule 1, paragraph 8,

> embedded productivity reductions represent the anticipated cost pressures that were eliminated or held flat within the capital and O&M budgets filed in the Custom IR proceeding as guaranteed savings which serve as a productivity assurance to ratepayer.

In other words, "the embedded cost reduction served as a ratepayer guarantee through lower up-front costs approved by the Board within rates." (Exhibit I.C.EGDI.FRPO.12) In addition, Enbridge estimates incremental O&M productivity to be approximately $10 million to $13 million from 2016 to 2018. The total estimated annual O&M savings are estimated between approximately $34 million and $35 million for the remainder of the CIR term.

Witnesses: L. Lawler
M. Yan

Enbridge estimates embedded Capital productivity savings of approximately $22 million for each year for the remainder of the CIR term. As discussed in Exhibit D, Tab 2, Schedule 1, paragraph 34, "due to the project nature of some of the capital expenditures, not all initiatives identified each year are expected to be sustained in the remaining Custom IR term" and as such incremental capital savings are estimated at $1.3 to $1.6 million each year during the remainder of the CIR term. Please see Table 1 for a summary of 2016 to 2018 estimated productivity savings.

These estimates are based on current information only and do not include productivity initiatives not yet developed, nor unanticipated cost pressures and uncontrollable external factors.

Table 1

Estimated 2016 to 2018 Productivity Savings		2016 (Estimate)	2017 (Estimate)	2018 (Estimate)
1	O&M: Embedded Reductions	(24.4)	(22.9)	(21.7)
2	O&M: Incremental Savings	(9.7)	(12.1)	(12.6)
3	Total Estimated O&M Reductions	(34.1)	(35.0)	(34.3)
4	Capital: Embedded Reductions	(21.7)	(21.7)	(21.9)
5	Capital: Incremental Savings	(1.6)	(1.3)	(1.3)
6	Total Estimated Capital Reductions	(23.3)	(23.0)	(23.2)
7	Total Estimated O&M & Capital Reductions	(57.5)	(58.0)	(57.5)

(b) Sustainability is one of the criteria used to assess what qualifies as a productivity initiative. The $58.9 million in productivity savings achieved in 2015, is the total of $26.9 million in O&M and $32 million in Capital. Based on current analysis, Enbridge expects sustainment beyond the CIR term of all of the productivity improvement activities which enabled O&M savings in 2015.

With regards to the sustainability of Capital productivity savings, without a complete Asset Management review available at this time, Enbridge Gas Distribution is unable to comment on capital productivity savings estimates beyond the current CIR.

Witnesses: L. Lawler
M. Yan

ENERGY PROBE INTERROGATORY #4

Interrogatory

Ref: Exhibit D, Tab 5, Schedule 1

Enbridge has consistently underperformed on the time to reschedule a missed appointment relative to the OEB approved standard.

a) In many cases, the explanation provided was that the calls arrived later than the 2 hours specified in the standard. Please explain more fully why the calls arrived later than the 2 hours.

b) In other cases, the appointment was rescheduled after the 2 hour limit without notifying the customer. Please explain why the customer was not notified in such circumstances.

c) What is Enbridge doing in 2016 to increase its compliance with the 100% OEB approved standard for this service quality indicator?

Response

Section 7.3.4.2 of GDAR establishes the standard for Time to Reschedule Missed Appointments ("TRMA"). Under Section 7.3.4.2, the distributor must track the percentage of customers contacted to reschedule the work within two hours of the end of the original appointment time. The OEB's standard for TRMA is 100%. The Company's result for 2015 was 94.8%, which represents only .15% or 71 out of 46,977 total appointments in 2015.

a) & b) In 2015, 0.038% (18/46,977) of Enbridge's appointments had an arrival time after the allotted two hour appointment window and 0.113% (53/46,977) of Enbridge's appointments were not notified of a rescheduled appointment within the two hours allotted. This happens for the following reasons:

- Emergency Response: Technicians are called upon to respond to emergencies. These types of calls are unpredictable and may require longer durations than anticipated.
- System Issues: The methodology when tracking the appointment re-schedules is time sensitive. If the main system or field devices are down,

Witnesses: D. Brault
K. Lakatos-Hayward
L. Parrington

the re-scheduling of the appointment will show as “missed”.

- Training (human error): Strict adherence to the process is required. Weekly monitoring has been put in place to ensure training issues are identified.

c) The Company’s efforts towards meeting the TRMA target of 100% are on-going. Cross functional teams meet weekly to review performance on Operational SQR metrics to address issues and to re-enforce training where necessary. The SQR Operational Committee meets monthly to address issues brought forward by the cross functional teams, to drive performance and to have overall oversight.

Witnesses: D. Brault
K. Lakatos-Hayward
L. Parrington

FRPO INTERROGATORY #16

Interrogatory

REF: Exhibit D, Tab 1, Schedule 4, page 4

Preamble: "*SIR Direct Resource Costs: Departmental labor costs are primarily capitalized salaries and employee expenses. The Company committed in its Custom IR application to find productivity in this area. The favorable variance results from reductions in Enbridge's workforce and targeted hiring practices which have led to delays in filling some vacancies.*
It is expected that the 2016 System Integrity and Reliability program costs will be at or higher than the 2016 OEB approved levels."

Please clarify the basis for the statement that 2016 costs will be higher than 2016 OEB approved levels.

a) Please provide specifics in terms of project acceleration, doing deferred work, etc.
b) Given the above answers, please breakout the 2015 underspend by each of those categories and actual savings in 2015.
c) How much of the 2015 savings are sustainable?

Response

The statement "2016 costs will be higher than 2016 OEB approved levels" pertains to SIR Program costs (not including DRC). Program costs will be higher than forecast primarily based on need to continue to address emerging risks associated with poorly performing vintage steel mains in highly congested urban areas.

a) The 2014/2015 direct capital spend for replacement mains was 230% higher than forecast for this period for the reasons noted above. This overspend was balanced by an underspend in Stations (due to capacity issues not yet realized) and Records (where work has been deferred as capital was re-allocated to higher risk assets).

b) Major categories of underspend were in Stations and Records totaling $10.4M. Most of this underspend was balanced by higher than forecast expenditures in other areas including replacement mains (see above), meter compliance units and Envision (see Exhibit D, Tab 1, Schedule 2, page 3).

c) The 2015 savings (which only total $1.1 million on the overall SIR budget – see Exhibit B, Tab 2, Schedule 4, page 2) are not sustainable due to the timing of projects as well as the need to address higher risk assets.

Witness: D. Broude

FRPO INTERROGATORY #17

Interrogatory

REF: Exhibit D, Tab 2, Schedule 1, page 8

Preamble: "*While actual spending in this area exceeds the budgeted amount by $11.7 million, savings of $13.8 million were achieved relative to the embedded target primarily through the establishment of long-term construction contracts to achieve cost certainty through the Custom IR term.*"

Please demonstrate how the $13.8 million in savings was determined.

a) Please break out any components and how much each contributed.

Response

The calculation of the savings is explained in response to VECC Interrogatory #6 at Exhibit I.D.EGDI.VECC.6. Please see the response to BOMA Interrogatory #15 at Exhibit I.D.EGDI.BOMA.15 for an explanation of how long-term construction contracts reduce costs for Enbridge.

Witnesses: L. Lawler
M. Yan

FRPO INTERROGATORY #18

Interrogatory

REF: Exhibit D, Tab 4, Schedule 1, page 14, Section 3.2

For each of the 4 pre-conditions (including sub-components), please provide:

a) Current status
b) Forecasted cost, where applicable
c) Expected completion

Response

The preconditions for the second phase of the Dawn Access Settlement Agreement (EB-2014-0323) are listed below with requested status and cost updates, where applicable.

Downstream Infrastructure must be in service:

The necessary downstream infrastructure required for the Dawn Transportation Service refers to: Segment A of the GTA Project, which will extend from the Parkway gate station to the Albion Road station; two TransCanada projects – the King's North Connection Project ("King's North") and the Vaughan Mainline Expansion Project ("Vaughan Mainline") – which will connect the Albion Road station to TransCanada's existing facilities[1]; and additional M12 capacity on the Union transmission system from Dawn to Parkway.

a) and c)

The status and in-service dates of these required services – to the best of the Company's knowledge at this time – is as follows:

Segment A of the GTA Project – On April 13, 2016, Enbridge filed a letter with the Board under EB-2012-0451 (the GTA Project), titled "Condition of Approval 2.6 – Completion of Construction". In the letter, it is noted that "all pipelines and facilities associated with Segment A of the GTA Project have been energized as of March 22, 2016."

[1] In addition to TransCanada's two pipeline projects, modifications to the compression facilities at TransCanada's Station 130 are also required to meet incremental firm transportation contracts on the system. The planned in-service date for the facility is November 1, 2016

Witnesses: D. Small
A. Welburn

King's North – The project was approved on July 30, 2015, in National Energy Board ("NEB") proceeding GHW-001-2014. In accordance with a condition in Order XG-T211-027-2015, TransCanada filed an updated King's North construction schedule on April 18, 2016. The timeline in the report indicated the project would be in service in late September 2016.

Vaughan Mainline – The GH-001-2016 proceeding is currently before the NEB. The contractual in-service date is November 1, 2017.

M12 – In Enbridge's evidence in GH-001-2016 (the Vaughan Mainline proceeding), filed on April 18, 2016, the Company states "At Union's annual OEB Stakeholder meeting, held April 13, 2016, Union reported that its 2017 expansion is currently forecast to be delivered on time and on budget."

b) Please see the response to FRPO Interrogatory #24 at Exhibit I.D.EGDI.FRPO.24 for the forecasted costs of the GTA Project.

   Enbridge has not received any updated cost forecasts for Union M12, King's North, or Vaughan Mainline.

Enbridge must have acquired the natural gas transportation services from Union Gas, or TransCanada, or both, that Enbridge needs in order to implement a bundled DTS:

a) The Company has acquired the transportation services from Union Gas and TransCanada needed in order to implement bundled DTS. Capacity required for DTS was a primary consideration in elections made by Enbridge in the 2017 New Capacity Open Seasons for both Union Gas and TransCanada.

b) A reasonable proxy for a forecast of upstream transportation costs can be found in the reference exhibit, at page 33 (the Transportation Contract Summary). The costs relevant to DTS are those of any contracts utilized for meeting DTS requirements; that is, any contracts utilized to move gas from Dawn to the CDA or EDA, excluding STS – Storage Transportation Service – which is considered a storage service for ratemaking purposes. An update to this schedule will be provided in the Enbridge 2017 Rate Application.

c) The acquisition of transportation services for DTS is complete. However, to reiterate the message in the interrogatory reference, DTS is contingent upon all four preconditions. Should there be a delay to any downstream infrastructure, for example, DTS would be delayed despite the Company having contracted for the necessary transportation services.

Witnesses: D. Small
A. Welburn

Enbridge must have completed system changes to EnTRAC, CIS and Open Link required to accommodate DTS and other future transportation services:

a) The Alternative Receipt Point (ARP) project will be completing the development stage by the end of June 2016, which is on target as planned. The next phase of the project will be Stabilization Testing and then the User Access Testing in early 2017.

   All three systems (Entrac, CIS and Openlink) will be enhanced to accept and operate with the addition of DTS receipt points.

b) Currently forecasted costs are on target at $6M. However, due to the immediate requirement to implement Cap & Trade it will delay the ARP project by approximately one month, if not longer. Also as testing phases of the project begin, there will be limitations around the availability of test environments with competing system projects such as the implementation of Cap & Trade and WAMS. The forecasted costs associated with these delays have not yet been calculated. In addition, if the Vaughan Mainline is delayed there may be additional costs to extend the warranty period for the ARP project.

c) The ARP project was planned to be completed in March 2017; with the anticipated delays the completion date is now tentatively pushed to April 2017.

Enbridge must have received approval of the Board for recovery from customers of the costs of implementing DTS, including particularly the costs of required system changes:

Approvals sought by Enbridge in EB-2014-0323 were granted at the oral hearing on November 20, 2014[2].

[2] EB-2014-0323 Transcript Volume 1, December 20, 2014, Page 17.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #19

Interrogatory

REF: Exhibit D, Tab 4, Schedule 1, page 21 and
EB-2015-0122 Exhibit I.D.EGDI.BOMA.13, part h)

Preamble: Page 21 states: *"The Company has included the acquisition of 200,000 GJ/day of Niagara Falls to Enbridge Parkway CDA capacity on TCPL."*

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

In the summer, when the market needs of Enbridge Parkway CDA do not require all of the 200,000 GJ/day contracted for, please describe how Enbridge moves the gas to storage?

a) Is it done by diversion or displacement? Please describe the two approaches and the one likely to be used.

Response

On a daily basis the Company will manage the demand requirements of the Central Delivery Area ("CDA") and the Eastern Delivery Area ("EDA") by balancing the supplies from various pipeline contracts and the utilization of storage.

With respect to the CDA and how the Company intends to manage excess supplies in the summer the Company has two options. The first would be that some portion of the natural gas supply that is procured at Niagara/Chippawa could be injected into storage. Typically that portion of the supply will be transported on the Company's firm transportation contract on the TransCanada PipeLines Limited ("TransCanada") Mainline as a diversion to the Kirkwall delivery point. A subsequent nomination would be submitted to Union Gas Limited to receive the supply at Kirkwall and transport it on the Company's C1 transportation contract to one of the delivery points at Dawn that correspond with storage facility that the supply is intended to be injected into. The Company would consider this to be a diversion as it is consistent with the Alternative Receipt and Diversion of Gas provision included in TransCanada's firm transportation toll schedule.

Alternatively, there may be instances where natural gas supply that is procured from Niagara/Chippawa is transported on the Company's firm transportation contract with

Witnesses: D. Small
A. Welburn

TransCanada to the contracted receipt point of Enbridge Parkway CDA for consumption in the franchise while natural gas supplies that are procured from other hub(s) are transported to Dawn for injection storage through diversions or as a delivery to the Storage Injection Point under the TransCanada STS contracts.

In either case, the Company does not utilize displacement to deliver natural gas supply to Dawn for injection into storage. The concept of displacement may be used by upstream transportation service providers to manage their operational and contractual commitments, but the Company cannot comment on that specifically.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #20

Interrogatory

REF: Exhibit D, Tab 4, Schedule 1, page 24

Preamble: "*In addition to requiring the transportation capacity to support the new DTS, Enbridge has experienced a decline in the contracted capacity for interruptible distribution services that are used to manage periods of high demand. A portion of the transportation capacity requested in the 2017 NCOS will be used to offset customer migration from interruptible distribution services and ensure the distribution system demand will continue to be met in a safe, reliable, and cost effective manner.*"

When did Enbridge last study the avoided costs associated with the interruptible rates?

a) Please file the analysis if available.
b) If interruptible rates were simply established in the most recent cost study, please provide a specific reference which details what costs would be avoided.
c) Given the above and the described migration, has Enbridge considered any other forms of incentive to optimize asset utilization through periodic demand reduction?

Response

The Company has not completed this type of detailed analysis for a number of years; however, on an annual basis as part of the gas supply planning process and how Peak Day Demand will be managed, a review of the current interruptible volumetric level is assessed. Based upon that assessment, the Company concluded that the interruptible volume available satisfies the needs of the Company and that the value of interruptible service is appropriate to its customers' needs as well. This would include the estimated reduction in the level of curtailment volume expected in the preliminary 2018 peak day demand estimates.

The Company has not considered any other forms of incentives for periodic demand reduction at this time.

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #21

Interrogatory

REF: Exhibit D, Tab 4, Schedule 1, page 24

Preamble: "*In addition to requiring the transportation capacity to support the new DTS, Enbridge has experienced a decline in the contracted capacity for interruptible distribution services that are used to manage periods of high demand. A portion of the transportation capacity requested in the 2017 NCOS will be used to offset customer migration from interruptible distribution services and ensure the distribution system demand will continue to be met in a safe, reliable, and cost effective manner.*"

How much of the 2017 capacity will be required to offset this migration?

a) What is the annualized cost of that capacity?

Response

Approximately 38,000 GJ per day of the transportation capacity associated with the 2017 NCOS was attributed to a forecasted reduction in interruptible distribution services. Based on current tolls for TransCanada and Union Gas, the annual cost would equate to $6.14 million as shown below.

		TransCanada					Union Gas				Total
	Contract Demand (GJ/d)	Receipt Point	Delivery Point	FT Toll ($/GJ)	Abandonment Surcharge ($/GJ)	Annual Cost ($M/year)	Receipt Point	Delivery Point	FT Toll ($/GJ)	Annual Cost ($M/year)	Annual Cost ($M/year)
Enbridge CDA	21,000	Union Parkway Belt	Enbridge CDA	0.1992	0.0057	1.57	Dawn	Parkway	0.095	0.73	2.30
Enbridge EDA	17,000	Union Parkway Belt	Enbridge EDA	0.4986	0.0259	3.25	Dawn	Parkway	0.095	0.59	3.84
						4.83				1.32	6.14

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #22

Interrogatory

REF: Exhibit D, Tab 4, Schedule 1, page 25

Preamble: "*Enbridge is no longer comfortable relying on peaking service and will replace it with the firm transportation that has been requested in the 2017 NCOS.*"

Has Enbridge evaluated the opportunity to contract for firm service, year-round at Iroquois to balance its portfolio and minimize winter peak requirements for the Eastern Region?

a) If so, please file the evaluation.
b) If not, why not?

Response

Demand in the northeast region of the United States has far outpaced natural gas supply that is available through the surrounding transportation infrastructure that is currently constrained. This situation has created a market at Iroquois that is often volatile from the perspective of cost and reliability which is contrary to the principles[1] that underpin the Company's gas supply plan. The Company continues to monitor the progress of new infrastructure projects that may help to relieve the transportation capacity constraints in this region. The construction of the Constitution Pipeline Project[2] is expected to provide the Iroquois market with access to natural gas supply from the Appalachian basin and provide much needed liquidity. When (and by some accounts, if) this project is completed, the Company fully intends to evaluate the liquidity of the Iroquois market and will determine at that time if natural gas supply procured from Iroquois would be of a benefit to the gas supply plan.

[1] Exhibit D, Tab 4, Schedule 1, page 8
[2] Information related to the Constitution Pipeline Project can be found at http://constitutionpipeline.com

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #23

Interrogatory

REF: Exhibit D, Tab 4, Schedule 1, page 26

Please provide the assumptions behind these figures or the next level of detail to understand how these figures were calculated.

a) Has EGD assessed the viability of increased forward purchases at Dawn during the winter season to mitigate? If so, please provide the analysis.
b) Please provide any developed terms of reference that have been published to initiate acquiring outside consulting services to study the load balancing needs.
c) Will Enbridge commit to filing the study for review and approval prior to purchasing additional storage?
    i) If not, why not?

Response

The Incremental Storage Analysis Summary that was provided in Figure 13 was based on a series of analyses that were conducted through the use of SENDOUT. Each SENDOUT analysis incorporated inputs that were used to develop the 2015 gas supply plan with two exceptions. First, different levels of demand over the winter period were used in each analysis. Second, an additional storage contract was added to each analysis.

The level of demand was increased over the winter period for each analysis to simulate the impact that prolonged colder than budget demand would have on how SENDOUT managed the gas supply portfolio and the resulting cost consequences. In order to quantify the magnitude of the demand increase, the winter demand was modeled through variations of Board approved Design Criteria methodology used to establish the peak day demand. The specific variations are outlined in Figure 13.

The new storage contract included parameters that were based on the storage contracts used for the 2015 gas supply plan analysis with the exception of the storage capacity. Typically the storage contract parameters that are entered into SENDOUT are predicated on executed agreements or known operational conditions. The new storage contract that was input for the purpose of this analysis incorporated a minimum storage capacity of 0 GJ and SENDOUT was permitted the discretion to increase the storage volume to the level that would result in the least cost consequence to the gas supply plan. Said differently, SENDOUT selected the storage capacity that would result in the

Witnesses: D. Small
A. Welburn

lowest overall costs for the gas supply plan. The storage capacity that was selected by SENDOUT in each of the analysis is reported in Figure 13 in the Incremental Storage Requirement (Bcf) column.

a) Yes, in addition to allowing SENDOUT to manage the increased demand during the winter through incremental storage as discussed above, SENDOUT was permitted to procure additional natural gas supply at Dawn in the winter. The results shown in Figure 13 are based on a preliminary analysis that was intended to illustrate the potential magnitude of incremental storage capacity that could be required. The Company is in the process of conducting a more detailed analysis and expects to file the results with the Board should the analysis conclude that incremental storage is recommended.

b) The Company released a Request For Proposal ("RFP") on March 11, 2016 to select an independent market expert to, among other things, develop commodity price forecasts related to different levels of demand and to assist in the evaluation of the results from the analysis. On April 11, 2016, ICF International was selected through the RFP to assist with the analysis.

c) Please see the response to a).

Witnesses: D. Small
A. Welburn

FRPO INTERROGATORY #24

Interrogatory

REF: Exhibit D, Tab 3, Schedule 1, Page 22-24
and EB-2012-0451 Decision with Reasons, page 54

Preamble: The Decision states *"However, the Board also agrees with parties that if there is no transportation revenue, distribution customers should not automatically bear the costs associated with the incremental capacity added to serve transportation customers. The evidence is that the cost difference between the NPS 36 pipeline (which would be required for distribution needs only) and the NPS 42 pipeline (which accommodates both distribution and transportation needs) is $55 million. Once Segment A is in service, if there are no transportation customers, then Enbridge will be required to record the revenue requirement impact of the $55 million in a deferral account for eventual recovery from transportation customers on Segment A."*

Please provide a projection of the forecast cost broken down between Segment A and Segment B breaking out the components of Material, Labour, Land and Overhead.

Response

As filed in response to CCC Interrogatory #4 in the EB-2016-0028 application, based on a forecast total GTA Project capital cost of $922M an estimated $413.3 million relates to Segment A. The remaining project costs are related to Segment B and distribution related facilities.

A detailed breakout of the actual costs will be included in the Post Construction Financial Report to be filed within 15 months of the March 2016 in-service dates for Segments A and B of the GTA Project.

Witness: S. Dodd

FRPO INTERROGATORY #25

Interrogatory

REF: Exhibit D, Tab 3, Schedule 1, Page 22-24
and EB-2012-0451 Decision with Reasons, page 54

Preamble: The Decision states *"However, the Board also agrees with parties that if there is no transportation revenue, distribution customers should not automatically bear the costs associated with the incremental capacity added to serve transportation customers. The evidence is that the cost difference between the NPS 36 pipeline (which would be required for distribution needs only) and the NPS 42 pipeline (which accommodates both distribution and transportation needs) is $55 million. Once Segment A is in service, if there are no transportation customers, then Enbridge will be required to record the revenue requirement impact of the $55 million in a deferral account for eventual recovery from transportation customers on Segment A."*

Please provide Enbridge's intent on the timing of the filing of the KPMG report.

Response

(a) Enbridge is not in a position to commit to the timing of when it will file the KPMG report, which is not complete. The Company expects that the KPMG report will be filed at such time as it is relevant and useful to determinations to be made by the OEB.

Witness: S. Dodd

FRPO INTERROGATORY #26

Interrogatory

REF: Exhibit D, Tab 3, Schedule 1, Page 22-24
and EB-2012-0451 Decision with Reasons, page 54

Preamble: The Decision states *"However, the Board also agrees with parties that if there is no transportation revenue, distribution customers should not automatically bear the costs associated with the incremental capacity added to serve transportation customers. The evidence is that the cost difference between the NPS 36 pipeline (which would be required for distribution needs only) and the NPS 42 pipeline (which accommodates both distribution and transportation needs) is $55 million. Once Segment A is in service, if there are no transportation customers, then Enbridge will be required to record the revenue requirement impact of the $55 million in a deferral account for eventual recovery from transportation customers on Segment A."*

Please describe the actions that Enbridge has undertaken to this point to implement the direction to record a revenue requirement given the current status of Segment A and TCPL's King's North.

a) Please provide Enbridge's position on the appropriateness of using the estimate of $55 million given current cost estimates to completion.

Response

The Greater Toronto Area Incremental Transmission Capital Revenue Requirement Deferral Account ("GTAITCRRDA") was established to record the revenue requirement associated with the forecast incremental $55 million capital costs associated with upsizing of the Albion Pipeline (Segment A of the GTA Project) from an NPS 36 pipeline to an NPS 42 pipeline. The account would only be required if at the time the Albion Pipeline is put into service there are no transportation customers, or there is no ability for transportation cutomers to utilize the Albion Pipeline (eg., due to incomplete third party facilities, such as TransCanada's King's North project).

Within the Company's 2014 – 2018 Customized Incentive Regulation ("CIR") rate proceeding, the Board fixed the capital costs and timing of the Company's GTA project for revenue requirement determination and rate setting purposes during the CIR term. As such, in the event that the GTAITCRRDA is required during the CIR term, the use of the forecast upsizing costs of $55 million is appropriate, as that aligns with the forecast costs being recovered in rates during the CIR term.

Witnesses: S. Dodd
A. Kacicnik
R. Small

At the time of filing Enbridge Gas Distribution's 2016 Rate Application (EB-2015-0114), there was uncertainty as to whether transportation service would be able to be offered during 2016, due to uncertainty as to whether TransCanada's King's North project would be completed. Therefore, Enbridge proposed and received approval to design rates based on the assumption that Rate 332 transportation service would not be offered in 2016. As a result, the 2016 GTAITCRRDA account was forecast to be used to recover the 2016 revenue requirement associated with the $55 million in forecast upsizing costs from future Rate 332 customers, while the remainder of the forecast Albion Pipeline revenue requirement was allocated for recovery from bundled customers.

At present, the GTA project including the Albion Pipeline segment has been placed into service, but TransCanada's King's North project has not been completed, and as such Rate 332 transportation service is not available. Therefore, as was contemplated in the 2016 Rate Application, Enbridge has begun recording 2016 revenue requirement associated with the $55 million in forecast upsizing costs in the GTAITCRRDA.

Currently, TransCanada King's North is expected to be in service in November 2016. Enbridge plans to hold an open season for its Albion Pipeline once its application for the Rate 332 tariff (EB-2016-0028) is approved, and expects to have transportation shippers on Rate 332 starting November 2016.

Enbridge plans to apply for the disposition of the GTAITCRRDA account in a future proceeding after Rate 332 customers begin to take service. In its Rate 332 rate schedule, filed at EB-2016-0028 Exhibit B, Attachment I, page 1, Enbridge indicates that

> Applicants taking Rate 332 transportation service will be required to pay any charges resulting from Board approved dispositions of Deferral and Variance account balances pertaining to Rate 332.

The revenue requirement that is recorded in the GTAITCRRDA will be recovered from Rate 332 customers. Once Rate 332 transportation service commences on the Albion Pipeline, the GTAITCRRDA will no longer be required. As set out in the EB-2016-0028 filing for approval of the Rate 332 tarriff, the rate for firm transportation service on the Albion Pipeline is based on recovery of 60% of the annual revenue requirement for the Albion Pipeline (through Rate 332 Contract Demand Charges for contracted capacity). During the CIR term, it will be based on the forecast costs included in the GTA project revenue requirement. However, when the annual revenue requirement for Segment A is adjusted at the end of the CIR term to account for the actual costs and timing of the the GTA project, then there will be corresponding changes to Rate 332.

Witnesses: S. Dodd
A. Kacicnik
R. Small

FRPO INTERROGATORY #27

Interrogatory

REF: Exhibit D, Tab 3, Schedule 1, Pages 22-24
and EB-2012-0459 Decision with Reasons, page 77

The Board Decision reads: *"APPrO had no comments on Rate 332, but recommended that Enbridge proactively develop daily interruptible service. Enbridge responded that no changes would be needed to be able to offer Transactional Services and if the opportunity to offer further services arises then the company will bring forward a proposal during the IR period. The Board is satisfied with Enbridge's response to APPrO's suggestion."*

What is the forecast peak day utilization of the distribution requirements of Segment A for the Winter of 2016/17?

a) Has Enbridge initiated any discussions with TCPL on the potential contracting of under-utilized distribution capacity for TCPL discretionary services for this winter or beyond.
   i) If not, why not?
   ii) If so, please provide the status of these discussions in respect to feasibility.
      (1) In addition, please provide Enbridge's views on the appropriateness of annualized reporting on the utilization of Segment A's distribution capacity.

Response

The forecasted peak day utilization of Segment A is expected to be 100% for the winter of 2016/2017.

a) The Company has included an Authorized Overrun Service ("AOS") in its EB-2016-0028 Storage and Transportation Access Rule ("STAR") Application that was filed with the Board on March 10, 2016. The Authorized Overrun Service would be offered as part of the proposed Rate 332 on any day where there is unutilized capacity on Segment A, which is referred to as the Albion Pipeline in the STAR Application. TransCanada is aware of the proposed offering of AOS and is an intervenor to the STAR application.

   i) Please see response to a) above.

Witnesses: D. Small
A. Welburn

ii) The STAR Application, and the AOS, is currently being considered by the Board.

(1) Segment A is part of the integrated distribution system that is managed by the Company to provide distribution services to its customers in the Greater Toronto Area ("GTA") region. As discussed above, the STAR Application includes an AOS. The AOS would be available to parties who have contracted for the proposed Rate 332 firm service when there is unutilized capacity on Segment A. In its Reply Submissions in the STAR Application, the Company has suggested that a further consultation related to the viability of other service ideas proposed by intervenors be conducted after some combined distribution/transmission operational experience has been gained with respect to the use of Segment A. Therefore, the Company suggests that any proposals or ideas regarding additional reporting would be more appropriately discussed at that time.

FRPO INTERROGATORY #28

Interrogatory

REF: Exhibit D, Tab 6, Schedule 2, Pages 17 and 18

Preamble: Related Party Transactions section provides summary level annual value and year-end balances for multiple Tidal Energy Marketing and Aux Sable companies.

For each of the respective companies, please define:

a) the nature of transactions e.g., gas commodity purchases, transportation services, optimization/exchange deals, etc.
b) and the value of each type of service
c) and the market value of the services received including how the market value was achieved.

Response

a) Enbridge Gas Distribution Inc. ("EGD") purchases natural gas from Tidal Energy Marketing Inc., both the Canadian and U.S. companies, and Aux Sable Canada LP. EGD's subsidiary, St. Lawrence Gas Company, Inc. sells optimization services to Tidal Energy Marketing Inc., the Canadian company.

b) Below is a breakdown of the value of each type of service:

Purchaser	Seller	Service	Value ($ CAD)
EGD	Tidal Energy Marketing Inc., Canadian company	Purchase of natural gas	$23 million
EGD	Tidal Energy Marketing Inc., U.S. company	Purchase of natural gas	$24 million
EGD	Aux Sable Canada LP	Purchase of natural gas	$62 million
Tidal Energy Marketing Inc., Canadian company	St. Lawrence Gas Company, Inc.	Optimization services	$7 million

c) The value was based on the applicable market index. The transactions entered into by EGD with Tidal were the result of an RFP process. The transaction with Aux Sable was one whereby the counterparty approached EGD about a possible gas supply transaction as discussed in EB-2015-0114 at Exhibit I.D1.EGDI.STAFF.4, page 2.

Witness: J. Barradas

IGUA INTERROGATORY #7

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 2, page 2.

The evidence lists as one of the three factors driving cost increases for the GTA project an escalation in *“construction bid price”.*

Please explain what *“construction bid price”* means and provide further explanation of why this cost component has increased.

Response

Please see the response to CME Interrogatory 3(a) at Exhibit I.D.EGDI.CME.3.

Witness: S. Dodd

IGUA INTERROGATORY #8

Interrogatory

Ref: Exhibit D, Tab 1, Schedule 4.

The evidence notes that EGD continues to evaluate the system integrity program work relative to the anticipated requirements as outlined in the EB-2012-0459 proceeding. The evidence further notes EGD's expectation that system integrity and reliability program costs in 2016 will be "at or higher than" 2016 Board approved levels.

(a) Please indicate what percentage of the "System Integrity Program" planned for the rate plan term has been completed to date.
(b) If EGD has revised cost estimates for the balance of its "System Integrity Program" please provide a table comparing those revised estimates, by year, to the comparable annual estimates from EB-2012-0459 for each of 2016, 2017 and 2018.
(c) Please identify and discuss any integrity issues identified to date which are expected to have material cost impacts during the balance of the rate plan term and/or in the immediately following years.

Response

(a) The System Integrity Program has spent 97% of the forecast budget presented in the Custom IR proceeding for the years completed to date (2014 and 2015). The focus of the System Integrity Program is risk reduction to the lowest practical level. This is being achieved through ongoing risk based assessments and other activities. Emerging risks, better understood risks and third party requirements identified on an ongoing basis have been analyzed and new information has been taken into account. As such, the originally anticipated program work within the System Integrity Program has been re-prioritized and modified. For this reason, it is difficult to identify the percentage of the System Integrity Program planned for the Custom IR term has been completed to date.

(b) Enbridge Gas Distribution has not revised the cost estimates for its System Integrity Program for the balance of the Custom IR term, but is managing the rolling portfolio of projects based on industry accepted Asset Management principles.

(c) The natural gas industry in general is faced with the challenges of operating aging infrastructure. The aging component is important to the extent that standards at the time of construction were less strict than today's standards in terms of construction practices, cathodic protection, quality and performance of the coatings etc. These challenges are further impacted by urban development encroaching on existing pipeline corridors, damages that occurred over the years associated with municipal infrastructure development that did not result in a loss of containment and went unreported, and municipal transportation infrastructure that can interfere with the cathodic protection of the assets. Enbridge is undertaking an Asset Health Review of its assets to better understand the health and condition of assets. This Asset Health review will result in the development of life cycle curves for each asset, and will provide direction to the future development of proactive risk mitigation programs.

SEC INTERROGATORY #3

Interrogatory

Ref: [Ex.D-1-2, p.2]

The evidence states that the GTA Reinforcement project costs are forecasted to be $235.5M more than what the approved amount in the EB-2012-0451 proceeding:

a. When does Enbridge plan on bringing forward this amount for a review for prudence?
b. Please confirm that none of those costs will be included in rates until the Board has reviewed the prudence of the variance.

Response

a. Please see the response to BOMA Interrogatory #10c at Exhibit I.D.EGDI.BOMA.10.

b. Confirmed.

Witness: S. Dodd

VECC INTERROGATORY #6

Interrogatory

Ref: D/T2/S1/pg. 8

a) If the actual spending for Customer Attachment capital exceeded the budgeted amount of $11.7 million then please explain how the net savings of $13.8 million was calculated.

Response

Embedded savings of $25.5 million were reflected within the 2015 capital budget related to Customer Attachments. That is, the budgeted amount reflected an up-front reduction of $25.5 million in 2015 which Enbridge sought to achieve in savings during the year. Spending in this area exceeded the budgeted amount by $11.7 million, which although short of the total reduction, still reflects savings of $13.8 million. The savings was calculated by taking the $25.5 million embedded committed reduction less the $11.7 million capital overspend compared to the IR budget ($25.5M - $11.7M = $13.8M).

Witnesses: L. Lawler
M. Yan