

November 24, 2017

VIA RESS, EMAIL and COURIER

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

Dear Ms. Walli

Re: Enbridge Gas Distribution Inc. ("Enbridge")

2018 Rate Adjustment Application ("Application")

Ontario Energy Board ("Board") File Number EB-2017-0086

Corrected Interrogatory Response

Further to Enbridge's submission dated November 13, 2017, enclosed please find a correction to Exhibit I.D1.EGDI.TCPL.3_Attachment 8. Details of the correction are provided below:

Exhibit	Original	Correction
Exhibit I.D1.EGDI.TCPL.3_Attachment 8	Exhibit I.D1.EGDI.TCPL.3_Attachment 8 Filed on Nov 13, 2017	There was an error in the data extract for commodity prices used to derive the landed cost analysis for the Niagara path, post-2023. Prices related to the Niagara pricing point post-2023 have been corrected in the attached table

The corrected exhibit has been filed through the Board's Regulatory Electronic Submission System and will be available on the Enbridge website at: www.enbridgegas.com/ratecase

Please contact the undersigned if you have any questions.

Yours truly,

(original signed)

Stephanie Allman Regulatory Coordinator

cc: Mr. D. Stevens, Aird & Berlis LLP (via email)
All Interested Parties EB-2017-0086 (via email)

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.STAFF.1 Page 1 of 2 Plus Attachment

BOARD STAFF INTERROGATORY #1

INTERROGATORY

Ref: Allowed Revenue and Sufficiency / Deficiency Summary Exhibit A1 / Tab 3 / Schedule 1 / Appendix B Exhibit D1 / Tab 6 / Schedule 2 / Page 1

Preamble:

Enbridge provided a summary highlighting the allowed 2018 revenue and the revenue deficiency. The summary shows the proposed 2018 allowed revenue compared to the 2018 placeholder allowed revenue.

Question(s):

- a) Please explain why the 2018 placeholder income tax shown at Line 16 of Exhibit A1 / Tab 3 / Schedule 1 / Appendix B / Page 1 does not match the placeholder income tax shown at Exhibit D1 / Tab 6 / Schedule 2 / Page 1. If the reason is that Exhibit D1 / Tab 6 / Schedule 2 / Page 1 does not include CIS / Customer Care-related income taxes, please provide a reference to where those taxes are shown. Please ensure that there is sufficient evidence on the record to allow for the reconciliation of the \$34.2 million proposed 2018 income tax amount.
 - b) Please provide a variance analysis with the necessary explanations, in the same level of detail as Exhibit A1 / Tab 3 / Schedule 1 / Appendix B, highlighting the 2017 OEB-approved allowed revenues compared to the proposed 2018 allowed revenues.

RESPONSE

a) The \$7.1 million variance between the income tax amount of \$34.2 million shown at Exhibit A1, Tab 3, Schedule 1, Appendix B, Page 1, Column 3, Row 16, and the \$27.1 million shown at Exhibit D1, Tab 6, Schedule 2, Page 1, Column 3, Row 32, reflects the tax amount attributable to CIS/Customer Care Costs. The breakdown of all 2018 CIS / Customer Care Costs sought for recovery, which results from the application of the Board Approved EB-2011-0226 Settlement Agreement as detailed in Exhibits D1, Tab 3, Schedules 1 to 3, by allowed revenue component, totaling \$131.1 million inclusive of tax of \$7.1 million, can be seen in Exhibit F1, Tab 2, Schedule 1, Column 7, Rows 1 to 22. The 2018 CIS/Customer Care tax amount

Witness: R. Small

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reflects the tax component embedded within the approved 2018 CIS asset revenue requirement amount shown at Exhibit D1, Tab 3, Schedule 2, Page 43, Column M, Row 3, and Exhibit D1, Tab 3, Schedule 3, Page 1, Column M, Row 3.

b) Attachment 1 to this response provides a comparison between each of the components of 2018 Updated Forecast allowed revenues, revenues at existing rates, and resultant deficiency, relative to the 2017 Approved values, and identifies the main drivers for the variances.

Witness: R. Small

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ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY)

		Col. 1	Col. 2	Col. 3	Col. 4
Line No.		2018 Total Updated Forecast Allowed Revenue (\$Millions)	EB-2016-0215 2017 Allowed Revenue (\$Millions)	Variance (\$Millions)	Note
	Cost of capital				
1. 2. 3.	Rate base Required rate of return	6,246.1 6.15 384.1	6,024.1 6.21 374.0	222.0 (0.06) 10.1	a) b) c)
	Cost of service				
4. 5. 6. 7. 8. 9.	Gas costs Operation and maintenance Depreciation and amortization Fixed financing costs Municipal and other taxes	1,754.9 467.5 305.5 1.9 50.4 2,580.2	1,603.1 459.9 297.7 1.9 47.9 2,410.5	151.8 7.6 7.8 - 2.5 169.7	d) e) f)
	Miscellaneous operating and non-operating rev	venue			
11.	Other operating revenue Interest and property rental Other income	(42.7) - (0.1) (42.8)	(42.7) - (0.1) (42.8)	- - -	
	Income taxes on earnings				
	Excluding tax shield Tax shield provided by interest expense	82.6 (48.4) 34.2	62.5 (48.1) 14.4	20.1 (0.3) 19.8	h)
	Taxes on sufficiency / (deficiency)				
	Gross sufficiency / (deficiency) Net sufficiency / (deficiency)	(81.5) (59.9) 21.6	- - -	(81.5) (59.9) 21.6	h)
	Sub-total revenue requirement Customer Care Rate Smoothing V/A Adjustment	2,977.3 4.9	2,756.1 2.8	221.2 2.1	i)
22.	Allowed revenue	2,982.2	2,758.9	223.3	
	Revenue at existing Rates				
24. 25.	Gas sales Transportation service Transmission, compression and storage Rounding adjustment	2,625.2 251.8 19.2	2,451.5 288.3 19.1	173.7 (36.5) 0.1	
	Revenue at existing rates	2,896.2	2,758.9	137.3	j)
28.	Gross revenue sufficiency / (deficiency)	(86.0)	-	(86.0)	

Exhibit I.A1.EGDI.STAFF.1

Attachment Page 2 of 2

Note: Explanation

a) Rate Base

As seen below, the increase in 2018 updated forecast ratebase is due to the increase in forecast net property plant and equipment that was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, reflecting an additional year of core capital spending. There were also increases in gas in storage and working cash allowance which were updated in accordance with CIR plan parameters, and reflect an updated volume forecast, gas supply plan, PGVA reference price, and O&M inputs.

Net property, plant and equip.	2018 <u>Forecast</u> 5,899.9	2017 <u>Approved</u> 5,695.9		Reviewed and approved in EB-2012-0459
A/R rebillable projects	1.4	1.4	_	Reviewed and approved in EB-2012-0459
Materials and supplies	34.6	34.6	-	Reviewed and approved in EB-2012-0459
Mortgages receivable	-	-	-	Reviewed and approved in EB-2012-0459
Customer security deposits	(64.6)	(64.6)	-	Reviewed and approved in EB-2012-0459
Prepaid expenses	1.0	1.0	-	Reviewed and approved in EB-2012-0459
Gas in storage	370.9	356.6	14.3	Updated per CIR plan parameters
Working cash allowance	2.9	(0.8)	3.7	Updated per CIR plan parameters
Total working capital	346.2	328.2	18.0	
Total rate base	6,246.1	6,024.1	222.0	_

b) Required rate of return

weighted average cost of debt rate, which reflects updated actual and forecast debt issuances and cost rates, partially offset by the impact of an increase in the forecast ROE, 8.84% in 2018 versus 8.78% in 2017 Approved. ROE and cost of debt forecast updates are performed in accordance with CIR plan parameters.

c) Cost of capital

The increase in the 2018 updated forecast cost of capital results from financing a higher rate base (discussed in a) above), partially offset by a lower required rate of return (discussed in b) above).

d) Gas costs

The increase in 2018 updated forecast gas costs is primarily due to a higher PGVA reference price and higher storage and transportation costs, partially offset by a decrease in forecast volumes and lower T-Service transportation costs. The updated forecast 2018 gas costs reflect an adjusted July 2017 PGVA reference price of \$188.611, while 2017 approved gas costs reflect an adjusted July 2016 PGVA reference price of \$166.901. Gas costs were updated in accordance with CIR plan parameters. Corresponding updates for price and volumetric impacts are also reflected in updated forecast revenue at existing rates.

e) Operation and maintenance

The increase in 2018 updated forecast O&M is detailed below, but is primarily driven by a higher forecast DSM budget, which has been updated in accordance with CIR plan parameters and reflects the approved budget included within Enbridge's DSM Multi-Year Plan proceeding EB-2015-0049. Customer Care and CIS costs have been updated in accordance with CIR plan parameters to reflect the EB-2011-0226 settlement agreement, which requires annual updates for the forecast number of customers and the current year's approved cost per customer. Pension and OPEB costs have been updated to reflect current forecast costs provided by Mercer, as per CIR plan parameters. The RCAM and Other O&M increases reflect amounts approved as part of the EB-2012-0459 decision.

	2018	2017		
	Forecast	Approved	Variance	
Customer Care / CIS	105.9	102.5	3.4	Updated per CIR plan parameters
DSM	67.6	62.9	4.7	Updated per CIR plan parameters
Pension and OPEB	20.8	24.7	(3.9)	Updated per CIR plan parameters
RCAM	35.9	34.8	1.1	Reviewed and approved in EB-2012-0459
Other O&M	237.3	234.9	2.4	Reviewed and approved in EB-2012-0459
Total O&M	467.5	459.9	7.6	_

f) Depreciation and amortization

The increase in 2018 updated forecast depreciation and amortization was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, and reflects the impact of growth in forecast gross property, plant, and equipment.

g) Municipal and other taxes

The increase in 2018 updated forecast municipal and other taxes was reviewed and approved within Enbridge's CIR proceeding EB-2012-0459, and reflects the impact of forecast capital growth an inflation.

h) Income taxes on earnings and deficiency

The increase in 2018 updated forecast income taxes is primarily attributable to a lower forecast income tax deduction for cash based pension and OPEB contributions (\$26.9M in 2018 versus \$51.4M in 2017), which was updated in conjunction with the updated forecast accrual based pension and OPEB costs, and the removal of the tax deduction related to the site restoration cost refund, as detailed in the Company's proposed Discontinuance of Site Restoration Cost Rider evidence at Exhibit D2, Tab 2, Schedule 1.

i) Customer Care Rate Smoothing V/A Adjustment

The Customer Care Rate Smoothing V/A Adjustment has been updated, similar to Customer Care & CIS O&M costs, to reflect the impact of the EB-2011-0226 settlement agreement which requires annual updates for the forecast number of customers, as well as the current year's approved cost per customer and normalized cost per customer.

j) Revenue at existing rates

The increase in 2018 updated forecast revenue at existing rates is due primarily to a higher gas commodity (PGVA) reference price embedded within rates (discussed in d) above), partially offset by the updated 2018 volumetric forecast.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.STAFF.2 Page 1 of 1

BOARD STAFF INTERROGATORY #2

INTERROGATORY

Ref: Conditions of Service Exhibit A1 / Tab 5 / Schedule 1 / Pages 5 and 17

Preamble:

Enbridge noted that it made a small number of revisions to its Conditions of Service. Question(s):

- a) Please confirm that the new language included in section 6.1 of the Conditions of Service is as follows: "If you do not set up a new Enbridge account, we will consider the premise vacant and eligible for discontinuance of service."
- b) If so, please advise whether this is the same treatment as has been previously applied but is now formally included in the Conditions of Service.

RESPONSE

- a) Confirmed.
- b) This is a new treatment articulated in the revised language. It reflects a process change wherein Enbridge will no longer bill premises where an account has not been established by the customer.

Witness: D. McIlwraith

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.CCC.1 Page 1 of 1

CCC INTERROGATORY #1

INTERROGATORY

Ex. A/T1/S1

Does EGD intend to use its 2018 approved rates as the basis for its rates beyond 2018?

RESPONSE

This question is not relevant to the 2018 Rate Adjustment Application. Enbridge's rates beyond 2018 will be determined in a separate future proceeding.

Witness: K. Culbert

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.CCC.2 Page 1 of 1

CCC INTERROGATORY #2

INTERROGATORY

(Ex. A1/T2/S1/p. 3)

The evidence states that the application will result in average 2018 rate increases of approximately 4.8% for residential customers. The average bill impact is 4.1% when the clearance of the 2017 Deferral and Variance Accounts are included. For each year 2014-2017 please provide the average rate and bill impacts for the residential customer class. Please provide this inclusive and exclusive of deferral and variance account impacts. Please provide the rate and bill increases inclusive of the Cap and Trade Compliance costs.

RESPONSE

The 2018 Rate Adjustment Application and resulting average rate impacts are the result of the Board's decision in the EB-2012-0459 Custom IR proceeding along with the updating of elements approved by the OEB to be updated in 2018. The Cap and Trade charges for 2018 are not yet approved.

The OEB approved elements to be updated on an annual basis for each of the years 2015 to 2018 are shown at Exhibit A1, Tab 3, Schedule 1, Appendix A.

The average rate and bill impacts for the years 2014 to 2017 were approved by the OEB in each of those years' Rate Adjustment Applications and are provided in response to Energy Probe Interrogatory #12, at Exhibit I.H1.EGDI.EP.12.

Witness: K. Culbert

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.EP.1 Page 1 of 1

EP INTERROGATORY #1

INTERROGATORY

- A). When did Enbridge's Executive Management Team review and approve the application for rates commencing January 1, 2018 prior to its filing with the OEB under the EB-2017-0086 docket?
- B). Please file all reports, presentations and supporting documents that were given to the members of the Executive Management Team to explain the application and obtain their approval.

RESPONSE

The Board's Decision with Reasons in EB-2012-0459 established a Custom IR framework to set Enbridge's rates over the period from 2014 to 2018. Specifically, the Board Decision and related Rate Order, approved placeholder Allowed Revenue amounts for 2015 to 2018 subject to adjustments each year to update certain elements of Allowed Revenue.

The resulting Allowed Revenue amount for each year is then used to set final rates based upon updated volume forecasts for that year.

The Rate Adjustment Applications for each of the years 2015 to 2018 were filed in accordance with the approved Customer IR framework and therefore it has not been necessary for these to be reviewed and approved by Enbridge's Executive Management Team.

Witness: A. Patel

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.EP.2 Page 1 of 2

EP INTERROGATORY #2

INTERROGATORY

Reference: Exhibit A Tab 1 Schedule 1 Appendix B; Exhibit F1 Tab1 Schedule 1 Table 1

Preamble: The deficiency amount calculated in the 2018 updated forecast represents the annual increase in rates that is required relative to existing July 1, 2017 Board-approved rates. Conversely, the deficiency calculated for the EB-2012-0459, 2018 placeholder was determined on a cumulative basis in comparison to April 1, 2013 Board-approved rates, and therefore is not reflective of the final rates which were approved by the Board for each of 2014, 2015, 2016, and 2017.

- A. Starting with Exhibit F1 Tab1 Schedule 1 Table 1 as a template, please provide a schedule in Excel Format that shows the EB-2012-0459 Rates and CIR amounts and placeholders for each year 2014-2018.
- B. Please add columns for each year that show actual approved/forecast rates.
- C. Please provide explanatory notes for deviations from the placeholders, including DSM, CIS and gas costs.
- D. Please provide additional notes on any other deviations from CIR rates.
- E. Please provide a chart using the Excel Spreadsheet data, that shows the 2014-2018 CIR annual revenue requirements based on placeholders and separately Actual 2014-18 revenue requirements with adjustments.

<u>RESPONSE</u>

The comparison of 2015 through 2017 annual CIR updated forecast Allowed Revenue information to the EB-2012-0459 Board Approved placeholder amounts was provided throughout the evidence and reviewed in each of the previous 2015 through 2017 annual Rate Adjustment proceedings. A summary comparison was provided at Exhibit A1, Tab 3, Schedule 1, Appendix B within each proceeding. Parties have already reviewed and the Board has already approved the updated Allowed Revenue amounts and rates for each of 2015, 2016 and 2017.

Witness: R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.A1.EGDI.EP.2 Page 2 of 2

EGD will not re-file information that was fully reviewed in previous Rate Adjustment proceedings as the re-filing of and re-review of that information is not relevant to the 2018 Rate Adjustment application. The 2018 update versus placeholder amounts are provided throughout the evidence in this proceeding and summarized at Exhibit A1, Tab 3, Schedule 1, Appendix B.

Witness: R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.B1.EGDI.STAFF.3 Page 1 of 1

BOARD STAFF INTERROGATORY #3

INTERROGATORY

Ref: Rate Base – Gas in Storage Exhibit B1 / Tab 1 / Schedule 1 / Page 3

Preamble:

Enbridge noted that the updated 2018 gas in storage value reflects July 2017 QRAM prices, whereas the 2018 placeholder gas in storage value reflected April 1, 2013 QRAM prices.

Question(s):

a) Please advise whether the gas in storage value (and the associated revenue requirement impact) will be updated at the time of Enbridge's next QRAM application to reflect the January 1, 2018 PGVA reference price.

RESPONSE

a) Confirmed. In accordance with QRAM approved guidelines, the commodity-related component of the 2018 forecast gas in storage value, and the associated allowed revenue / revenue requirement impact, will be updated as part of each of the January 1st, April 1st, July 1st, and October 1st 2018 QRAM applications to reflect the impact of updated reference prices.

Witnesses: D. Small

R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.STAFF.4 Page 1 of 3

BOARD STAFF INTERROGATORY #4

INTERROGATORY

Ref: Operating Revenues – Average Use Exhibit C1 / Tab 2 / Schedule 1 / Appendix A / Pages 6-7

Preamble:

In Tables 5 and 6 of Exhibit C1 / Tab 2 / Schedule 1 / Appendix A, Enbridge provided the monthly baseload average use per customer and heatload average use per customer for the Rate 1 and 6 classes.

Question(s):

a) Please provide the detailed calculation of the monthly baseload average use and heatload average use for each of Rate Classes 1 and 6.

RESPONSE

The calculations of the average monthly baseload and average monthly heatload per customer follow for Rate 1 (Table 1) and Rate 6 (Table 2). Unlike the annual average use forecast methodology which uses regression models, average monthly baseload and heatload values rely on historical monthly profiles of average use.

As detailed at Exhibit C1, Tab 2, Schedule 1, page 15, paragraph 35, summer baseload is calculated as the average total consumption for the months of July and August. The forecasts of summer baseload for Rate 1 and Rate 6 are 55 m³ and 660 m³ respectively for 2018. For all other months, summer baseload is profiled using seasonality factors estimated by load analysis to reflect the seasonal aspect of baseload demand. 2018 seasonality factors are shown at line 1.2 in the tables. The product of the seasonality factors and the summer baseload values per month then determine the average monthly baseload per customer (line 1.3). Average monthly heatload per customer (line 1.4) is calculated by subtracting average monthly baseload per customer from the monthly average use per customer.

Witnesses: R. Cheung

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.STAFF.4 Page 2 of 3

			<u>Notes</u>	Exhibit C1, Tab 2, Schedule 1, Appendix A, Table 5		Summer baseload * seasonality factors (row 1.2)	Row 1.1 - Row 1.4
		Col. 13	Total	2,363		751	1,612
		Col. 12	Dec	290	1.1864	92	225
	MER	Col. 11	Nov	181	1.1337	62	119
	GENERAL SERVICE RATE 1 2018 BUDGET - AVERAGE BASELOAD AND AVERAGE HEATLOAD PER CUSTOMER	Col. 10	<u>Oct</u>	98	1.0181	26	30
	TLOAD PE	Col. 9	Sep	54	1.0000	52	0
	NTE 1 AGE HEA ⁻	Col. 8	Aug	22		54	0
TABLE 1	GENERAL SERVICE RATE 1 SASELOAD AND AVERAGE	Col. 7	<u>Inf</u>	26		26	0
TAE	NERAL SE ELOAD AI	Col. 6	<u>lun</u>	73	1.1908	92	7
	GE AGE BAS	Col. 5	May	143	1.1812	92	78
	ET - AVER	Col. 4	Apr	259	1.2148	29	193
	18 BUDG	Col. 3	Mar	356	1.2970	71	285
	<u>200:</u>	Col. 2	Feb	411	1.2343	89	343
		Col. 1	Jan	400	1.2348	89	332
				Budget Average Use per Customer (m³)	Monthly Seasonality Factors applied to Baseload	Average Baseload per Customer (m³)	Average Heatload per Customer (m³)
			Item.	1.1	1.2	1.3	1.4

Witnesses: R. Cheung M. Suarez

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.STAFF.4 Page 3 of 3

				Notes	Exhibit C1, Tab 2, Schedule 1, Appendix A, Table 6		Summer baseload * seasonality factors (row 1.2)	Row 1.1 - Row 1.4
			Col. 13	Total	28,656		10,959	17,697
			Col. 12	Dec	3,467	1.6331	1,078	2,389
	0	MER	Col. 11	Nov	2,293	1.3926	920	1,373
	OT SI TO 0.	טו גרטט עו	Col. 10	Oct Oct	1,066	1.0085	999	400
	GENERAL SERVICE RATE 6 3019 BUINGET AVERAGE BASELOAD AND AND AND AND AND AND AND AND AND A	LOAD PE	Col. 9	Sep	629	1.0000	629	0
	TE 6	AGE IIEA	Col. 8	Aug	652	1	652	0
TABLE 2	GENERAL SERVICE RATE 6	ND AVER	Col. 7	Int	899	1	899	0
TAE	NERAL SE	ELUAD A	Col. 6	unr	935	1.2740	841	94
	GE	AGE DAS	Col. 5	May	1,881	1.3782	910	971
	01/VE	EI-AVEN	Col. 4	Apr	3,198	1.4823	979	2,220
	01	10 0000	Col. 3	Mar	4,374	1.7730	1,171	3,203
	Ò	707	Col. 2	Feb	5,144	1.9243	1,271	3,873
			Col. 1	Jan	4,319	1.7333	1,145	3,174
					Budget Average Use per Customer (m³)	Monthly Seasonality Factors applied to Baseload	Average Baseload per Customer (m³)	Average Heatload per Customer (m³)
				Item.	1.1	1.3	1.3	1.4

Witnesses: R. Cheung M. Suarez

Exhibit I.C1.EGDI.STAFF.5

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BOARD STAFF INTERROGATORY #5

INTERROGATORY

Ref: Operating Revenues - Cap & Trade Impact on 2018 Volume Forecast

Exhibit C1 / Tab 2 / Schedule 1 / Appendix C Ontario Climate Change Action Plan (https://www.ontario.ca/page/climate-change-action-plan)

Preamble:

Enbridge noted that it captured the impact of cap and trade on its 2018 volume forecast within the regression models through the gas price variable (as an addition to the commodity, transportation, load balancing and distribution component of Rate 1 and Rate 6 gas prices).

Enbridge noted that its average use regression models estimate an average price elasticity of demand of -0.04% for Rate 1 customers and -0.05% for Rate 6 customers for every 1% change in price.

Enbridge stated that cap and trade obligations contribute to an incremental 9.8% to Rate 1 gas prices and 12.5% to Rate 6 gas prices. Using the estimated elasticities set out above, the impact of Cap and Trade costs is an incremental decrease in projected average use of 9 m3 per Rate 1 customer and a decrease in projected average use of 174 m3 per Rate 6 customer.

Enbridge further stated that as the price change is evident as a single price signal for customers, the impact on demand cannot be broken out into its potentially distinct impacts as it is not perceived separately. As a result, the impact on demand of cap and trade costs has to be assumed to have the same impact as a regular price change. No other intrinsic signal can be inferred.

Question(s):

- a) Please confirm that this is the first year that Cap and Trade was reflected in the Enbridge's volume forecast.
- b) Please advise whether the price elasticity of demand of -0.04% for Rate 1 customers and -0.05% for Rate 6 customers for every 1% change in price is the same as was used in previous years.

Witnesses: S. McGill

F. Oliver-Glasford

Exhibit I.C1.EGDI.STAFF.5

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c) Enbridge stated that it has to assume that the impact of cap and trade is the same as a regular price change as it is not perceived separately by customers. OEB staff notes that cap and trade-related costs have been communicated to customers broadly through bill inserts, media reports, etc. Please discuss whether Enbridge believes that customer demand might be further impacted by cap and trade beyond the price elasticity of demand for non-economic reasons (e.g. environmental beliefs, etc.). Please discuss whether Enbridge has attempted to quantify the impact of these non-economic factors on demand for the 2018 volume forecast.

d) Ontario's Climate Change Action Plan includes funding for a number of activities that are designed to reduce energy use in homes and buildings in 2018. Furthermore, Enbridge proposed, in its originally filed evidence (prior to the removal of the cap and trade-related evidence in accordance with the OEB's Letter of Direction), to install geothermal loops for its customers in 2018. Please advise whether the estimated impact of these types of activities was reflected in Enbridge's 2018 volume forecast. Please provide supporting rationale.

RESPONSE

- a) Confirmed. 2018 is the first year that Cap and Trade impacts were modelled into the volumes forecast. As noted in EB-2016-0216 (Exhibit C2, Tab1, Schedule 3, page 22), Cap and Trade impacts were not explicitly modelled as details on the recovery of compliance costs were not available at the time 2017 volumetric forecasts were generated.
- b) The price elasticities of demand referenced for Rate 1 and Rate 6 are values generated by the regression models in 2018 utilizing historical data up to 2016. Regression models are re-run annually to include the impacts of the latest year of actual information. Re-running the models effectively re-estimates the coefficients of the driver variables to reflect or refine the relationship between dependent and independent variables. As such, the coefficients or price elasticities of demand change year to year although not by a significant amount.
- c) Enbridge acknowledges that customer demand may be impacted by any number of factors. The use of the demand elasticities allows for an objective and measurable way of quantifying the impact of drivers on demand within a model that can be tested for statistical significance. The use of the price elasticity of demand estimates the relationship between quantifiable changes in price and quantifiable changes in demand. Generally, non-economic drivers, specifically customer values in this case, are more qualitative in nature and are beyond the methods currently used to estimate

Witnesses: S. McGill

F. Oliver-Glasford

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.STAFF.5

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demand. At this time, Enbridge has not identified an approach that would allow it to isolate and quantify impacts of specific customer values on demand.

d) Enbridge has not forecast volume impacts from new activities that may be supported by Climate Change Action Plan funding, because the timing, scope and impact from such new activities were not sufficiently known at the time that the volume forecast was prepared. The Company's current Geothermal Energy Services forecast for 2018 calls for 200 geothermal customer additions to be added in May through September 2018. As such, there will be very limited impact on gas volumes delivered by the Company in 2018. The Company's 2018 volume forecast did not include volume reductions in respect of forecast 2018 geothermal business activities.

Witnesses: S. McGill

F. Oliver-Glasford

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.1 Page 1 of 1

BOMA INTERROGATORY #1

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, p2

What are the 2017 actuals – year to date for Table 1?

RESPONSE

The methodology for forecasting volumes and all inputs to the volumetric determination utilizes the last full year of actual data at the time that forecasts are developed for the rate application. This approach has been applied consistently for ratemaking purposes. For the 2018 forecast, actual data up to and including 2016 were utilized. From that standpoint, it is the Company's position that partial year information is not indicative of full year results, and is therefore not appropriately used to inform test year expectations.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.2 Page 1 of 1

BOMA INTERROGATORY #2

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, p13

How many contract customers were "lost"? What does "lost" mean in this context? What volumes do they represent, and how was it calculated?

<u>RESPONSE</u>

The 2018 Contract volume budget is lower than the 2017 Contract volume budget by 48.2 10⁶m³ as a net result of (1) the loss of three customers (amounting to a decline of 52.6 10⁶m³), partially offset by (2) the addition of two new contract market customers (increased volume of 4.4 10⁶m³). Customers were lost due to plant shutdown or relocation of their operations to other areas.

The volumetric detail is shown further at Exhibit C3, Tab 2, Schedule 3, page 3, column 6 and column 9, line 4.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.3 Page 1 of 1

BOMA INTERROGATORY #3

INTERROGATORY

Ref: Appendix A, p2, Table 1 re: normalized actual use

Please add 2017 actual average use to date number to Tables 1 and 2.

RESPONSE

Please see response to BOMA 1 at Exhibit 1.C1.EGDI.BOMA.1.

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BOMA INTERROGATORY #4

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix B, p1

- (a) Where is the forecast 2018 customer additions of 30,449 shown in the Tables and Schedules?
- (b) Please explain how the number is derived, including the relative importance of each factor considered, for both rate 1 and rate 6 customers.

RESPONSE

- (a) Customer Additions of 30,449 can be found in Exhibit C2, Tab 1, Schedule 4, page 3, Table 1.
- (b) As explained in Exhibit C2, Tab 1, Schedule 4, the 2018 customer additions forecast was derived based on a number of sources including information gathered through direct contact with builders, developers, and municipalities as well as economic indicators such as housing starts, GDP growth, employment, and mortgage rates. The most important of these factors are housing starts and grass roots information from contacts with builders, developers and municipalities. This forecasting approach is consistent with the process used by the Company and approved by the Board in previous rate applications.

The customer additions forecast is included in the forecast of unlocks and layered onto the number of year-end customers. Not all customer additions become unlocked customers due to timing lags. Please see paragraphs 5 to 7 in Exhibit C1, Tab 2, Schedule 1, Appendix B for further details on the methodology for deriving forecast unlock customers.

Exhibit I.C1.EGDI.BOMA.5

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BOMA INTERROGATORY #5

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix 1, Table 5

- (a) Please explain the variation in the rate of increase in unlocked meters from January through to December.
- (b) Please explain the derivation of the baseload average use (line 4) in the Table for the months other than July and August, which are set at zero.
- (c) What influencing factors are used, and what is the weight accorded to each of these factors? Please explain for each of the ten months, separately.

RESPONSE

- (a) The opening balance of unlocks in January is the base from which any additional unlocks from new customer additions, changes from red lock meters, seasonal locks, and vacancies apply. During the course of the year, unlocks generally increase month to month from new customers unlocks added in the current year. However, starting in May red locked meters reduce the number of unlocks as heating service is less critical and the Company looks to act on its collection policies. This decline in unlocks continues into the summer months as seasonal locks apply. Over this period, depending on the construction season, new customer unlocks serve to offset the locks from customer non-payment or temporary locks as customers suspend service. As temperatures start to drop in September and October, unlocks increase steadily month over month to December from a combination of seasonal unlocks and new customer unlocks.
- (b) and (c)

Please see the response to Board Staff Interrogatory #4 at Exhibit 1.C1.EGDI.STAFF.4 as well as Exhibit C1, Tab 2, Schedule 1, page 15, Paragraph 35.

Water heating demand typifies baseload consumption, and seasonality factors account for the variation in baseload demand over the course of the year. Seasonality factors are derived using the monthly profile of water heating demand relative to July and August consumption as the minimum level of demand.

For each month of water heating demand, average use consumption for water heating load revenue class is divided by the average of July and August consumption to

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generate the seasonality factor for the month. The seasonal baseload is used to determine the residual heatload that is normalized for weather impacts.

Exhibit I.C1.EGDI.BOMA.6

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BOMA INTERROGATORY #6

INTERROGATORY

Ref: 2018 Volumes

- (a) Please confirm that for general service normalization, there are thirty-six grouping of revenue classes/operating regions, and weather zones. If not, please list the groupings and describe each one.
- (b) Please outline, with a map, the six operating regions and the three weather zones, showing borders among them.

RESPONSE

a) General Service normalization is performed by groupings comprised of revenue classes, operating regions (within weather zones) and gas service types. There are seven heating revenue classes, six operating regions and four customer service types which result in one hundred and sixty-eight groupings in the weather normalization process. The following tables provide descriptions for each group.

Heating Revenue Classes

Revenue Class Group Number	Revenue Class Description	Rate Class
10	Residential Space Heating	Rate 1
20	Residential Space Heating, Water Heating and Other Uses	Rate 1
50	Residential Space Heating, Water Heating and Pool Heating	Rate 1
12	Apartment Space Heating	Rate 6
48	Commercial Space Heating	Rate 6
79	Commercial Air Condition	Rate 6
73	Industrial Space Heating	Rate 6

Exhibit I.C1.EGDI.BOMA.6

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Operating Regions

Operating Region	Weather Zone
Metro (Toronto)	Central
Western (GTA West)	Central
Central (GTA East)	Central
Northern (GTA North)	Central
Eastern (Ottawa)	Eastern
Niagara	Niagara

Customer Gas Service Types

Gas Type	Service Type Description
SGC	Sales
TSW	Western T-service
TSO	Ontario T-service
TSD	Dawn T-service

Exhibit I.C1.EGDI.BOMA.6

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b) The map below outlines the operating regions. With regards to weather regions, regions 1 to 4 on the map belong to the Central weather zone, region 5 on the map is the Niagara weather zone, and region 6 is the Eastern weather zone.

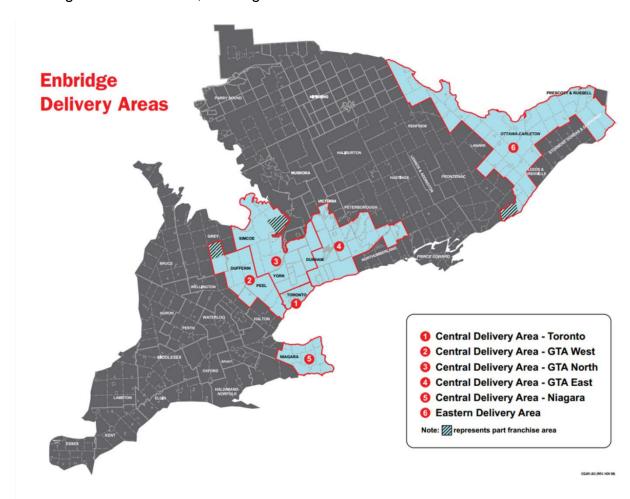


Exhibit I.C1.EGDI.BOMA.7

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BOMA INTERROGATORY #7

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, p14

Please explain why balance point degree days do not affect the company's degree day forecast. Does the degree day forecast still reflect only degree days below 18°C? Should they not be the same, given that degree days are used to normalize the actual monthly consumption? What is the impact on the volume forecast of using the degree days shown on this page, rather than the 18°C?

RESPONSE

The Company's Degree Day forecast methodology is assessed using Environment Canada degree days relative to the traditional 18°C. Environment Canada degree days are used because of the extensive history that can be leveraged to inform weather patterns. Degree day forecasting methodology is approved based on the results using Environment Canada degree days.

Environment Canada degree days are converted to balance point degree days by shifting the reference temperature at which degree days are counted or recorded. Both are expressions of the same weather expectation, just with different temperature thresholds.

For purposes of average use volumetric forecasting, balance point degree days equivalent of the OEB approved degree day forecast (using 18°C) are used, as they are more closely tied to heatload consumption. Average use forecasts are determined using the equivalent balance point degree days in the models. Hence, for normalization purposes, actual consumption is adjusted back to the balance point degree days used in the forecast. Consistent balance point degree days are used in the forecast and in the normalization of actuals.

Exhibit I.C1.EGDI.BOMA.8

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BOMA INTERROGATORY #8

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix A, p6, Table 5

- (a) Please show the calculation for each grouping's average load, base load and heat load for each month, and show those amounts for each month for each grouping.
- (b) Please show the number of monthly customers and monthly total consumption for each revenue class for each of rate 1 and rate 6.
- (c) Please provide the aggregation of the results provided for each grouping asked for in (b) above, to the numbers that are shown in Tables 5 and 6.
- (d) Do the balance point degree days vary for different groupings, other than between the three weather regions on p14? If so, please explain why and how.
- (e) Has EGD made empirical studies of the influence of higher or lower gas prices on demand, in addition to the results supplied by the econometric model? If so, what are the results?

RESPONSE

a), b) & c)

Due to the time constraints and the work associated with other interrogatories, the derivations of average use per customer, baseload, heatload, monthly customers and monthly consumptions as shown in Exhibit C1, Tab 2, Schedule 1, Appendix A, Tables 5 and 6, cannot be provided for all of the one hundred and sixty-eight groupings (refer to BOMA Interrogatory #6 at Exhibit 1.C1.EGDI.BOMA.6 for a list of the groupings). The following twelve tables show the calculations by groupings comprised of rate classes (Rate 1 and Rate 6) and operating regions (six regions).

Tables 1 to 6 show the calculations for Rate 1 in the six operating regions. The aggregated results of these tables would reconcile to Table 5 in Exhibit C1, Tab 2, Schedule 1, Appendix A.

Similarly, Tables 7 to 12 show the calculations for Rate 6 in the six operating regions. The aggregated results of these tables would reconcile to Table 6 in Exhibit C1, Tab 2, Schedule 1, Appendix A.

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TABLE 1	GENERAL SERVICE RATE 1, METRO REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BU	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	OLUME, C	CUSTOME	ERS & AVE	ERAGE US	띯				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		<u>Jan</u>	Feb	Mar	Apr	Мах	<u>Inr</u>	피	Aug	Sep	<u>Oct</u>	Nov	Dec	Total	Notes
1:1	Budget Volumes (10 ⁶ m³)	217.6	223.6	193.6	138.0	74.1	36.3	26.0	24.9	25.0	45.7	100.7	160.2	1,265.7	
1.2	Customer Meters Budget	490,427	490,966	491,461	491,847	491,800	491,468	491,298	491,763	492,269	493,801	495,188	496,334	492,385	
1.3	Budget Average Use per Customer (m³)	444	456	394	281	151	74	23	51	51	95	203	323	2,571	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m³)	99	29	69	63	63	29	53	51	51	54	62	63	726	
1.5	Heatload Average Use per Customer (m³)	378	389	325	217	88	7	0	0	0	39	142	260	1,845	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

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2018

					GEN 2018 BUI	GENERAL SERVICE RATE 1, WESTERN REGION BUDGET - VOLUME, CUSTOMERS & AVERAGE	WICE RAT	TE 1, WES	STERN RE	GENERAL SERVICE RATE 1, WESTERN REGION 2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	щ				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	<u>lun</u>	<u>lnr</u>	Aug	Sep	<u>Oct</u>	Nov	Dec	Total	Notes
1.1	Budget Volumes (10 ⁶ m³)	140.4	144.0	124.2	91.6	52.5	27.9	22.9	22.1	21.5	31.6	64.8	107.0	850.4	
1.2	Customer Meters Budget	345,999	346,380	346,729	347,005	346,971	346,734	346,611	346,945	347,308	348,405	349,399	350,227	347,393	
1.3	Budget Average Use per Customer (m^3)	406	416	358	264	151	80	99	2	62	91	186	305	2,448	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m³)	79	80	83	76	75	73	99	64	62	99	71	79	873	
1.5	Heatload Average Use per Customer (m^3)	326	336	276	187	76	∞	0	0	0	25	115	227	1,576	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

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TABLE 3	GENERAL SERVICE RATE 1, CENTRAL REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	JGET - VC	OLUME, C	CUSTOME	RS & AVE	ERAGE US	띩				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	<u>nn</u>	<u>lul</u>	Aug	Sep	<u>Oct</u>	Nov	Dec	Total	Notes
1.1 (Budget Volumes (10 ⁶ m³)	81.5	84.2	73.0	54.7	29.8	15.2	12.4	12.1	11.9	18.5	38.3	59.8	491.4	
1.2	Customer Meters Budget	224,548	224,795	225,023	225,200	225,180	225,024	224,946	225,162	225,394	226,106	226,749	227,285	225,451	
1.3	Budget Average Use per Customer (m³)	363	375	324	243	132	89	55	7 5	53	82	169	263	2,180	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	99	9	69	29	61	09	25	54	53	26	09	63	7.27	
1.5	Heatload Average Use per Customer (m³)	297	309	256	176	71	7	0	0	0	26	109	200	1,453	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

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TABLE 4	GENERAL SERVICE RATE 1, NORTHERN REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BU	DGET - V	OLUME, C	SUSTOME	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	ERAGE US	띪				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	Мау	<u>Inn</u>	미	Aug	Sep	<u>Oct</u>	Nov	Dec	Total	<u>Notes</u>
1.1	Budget Volumes (10^6m^3)	191.7	194.7	171.8	127.0	72.2	37.7	29.4	28.5	28.0	42.6	9.68	139.2	1,152.5	
1.2	Customer Meters Budget	459,794	460,300	460,763	461,132	461,087	460,770	460,610	461,053	461,531	462,992	464,311	465,411	461,646	
1.3	Budget Average Use per Customer (m³)	417	423	373	275	157	82	2	62	61	92	193	599	2,497	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m³)	76	77	8	76	76	74	64	62	61	62	69	73	852	
1.5	Heatload Average Use per Customer (m³)	341	346	291	199	81	∞	0	0	0	30	124	226	1,646	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

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TABLE 5	GENERAL SERVICE RATE 1, EASTERN REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BC	DGEI - V	2018 BUDGEl - VOLUME, CUSTOMERS & AVERAGE USE	USIOIMI	ERS & AV	EKAGE U	씱				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	<u>lun</u>	미	Aug	Sep	Oct	Nov	Dec	Total	Notes
1.1	Budget Volumes $(10^6 \mathrm{m}^3)$	120.0	123.1	103.6	74.8	39.6	20.1	15.4	14.2	15.5	24.4	52.3	86.0	689.1	
1.2	Customer Meters Budget	329,921	330,287	330,622	330,888	330,857	330,625	330,510	330,832	331,178	332,230	333,183	333,976	331,259	
1.3	Budget Average Use per Customer (m³)	364	373	313	226	120	61	47	43	47	73	157	257	2,081	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	57	55	61	55	54	55	47	43	45	45	25	55	624	
1.5	Heatload Average Use per Customer (m^3)	307	318	253	171	99	9	0	0	н	78	105	202	1,457	
	Meter Reading BP DD (Eastern)	0.969	716.0	568.0	381.0	147.0	9.0	0.0	0.0	2.0	86.0	288.0	494.0	3,387.0	

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TABLE 6	GENERAL SERVICE RATE 1, NIAGARA REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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Col. 1 Col. 2 Col. 3 Jan Feb Mar Ma	Col. 1 Col. 2 Col. 3 Jan Feb Mar Ma	Col. 1 Col. 2 Col. 3 Jan Feb Mar Ma	Col. 1 Col. 2 Col. 3 Jan Feb Mar Ma	Col. 1 Col. 2 Col. 3 Jan Feb Mar Ma	Signature Sign	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 1 Col. 2 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col.	Col. 1 Col. 2 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10		2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 2 Col. 3 Col. 5 Col. 6 Col. 7 Col. 9 Col. 10 Col. 11 Feb Mar Apr May Jun Jul Aug Sep Oct Nov	1.1 Br	1.2 CL	1.3 BL	1.4 Ba	1.5 Pe	≥ ≤	
Col. 2 Col. 3 Feb Mar 55.9 50.0 156,488 156,645 357 319 49 51 49 51 560.0 473.0	Col. 2 Col. 3 Feb Mar 55.9 50.0 156,488 156,645 357 319 49 51 49 51 560.0 473.0	Col. 2 Col. 3 Feb Mar 55.9 50.0 156,488 156,645 357 319 49 51 49 51 560.0 473.0	Col. 2 Col. 3 Feb Mar 55.9 50.0 156,488 156,645 357 319 49 51 49 51 560.0 473.0	Col. 2 Col. 3 Feb Mar 55.9 50.0 156,488 156,645 357 319 49 51 49 51 560.0 473.0	Col. 2 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Feb Mar Apr May Jun Jul Aug Sep 55.9 50.0 35.8 18.6 9.4 6.5 6.6 6.6 156,488 156,645 156,755 156,649 156,743 156,904 7 49 51 528 119 60 42 42 42 49 51 53 40 50 42 42 42 560 51 53 40 50 42 42 42 49 51 53 40 50 42 42 42 5600 43 51 78 10 0 0 0 0	Col. 2 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Col. 1	Col. 2 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Col. 11 Feb Mar Apr May Jun Jul Aug Sep Col. 10 Col. 11 55.9 50.0 35.8 18.6 9.4 6.5 6.6 6.6 10.2 1.8 156,488 156,645 156,769 156,769 156,649 156,743 156,743 156,904 157,395 157,840				udget Volumes 0 ⁶ m³)	ustomer Meters udget	udget Average Use ?r Customer (m³)	sseload Average Use ?r Customer (m³)	eatload Average Use ?r Customer (m³)	Meter Reading BP DD (Niagara)
Col. 3 Mar 50.0 319 5473.0	Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 So.0 35.8 18.6 9.4 6.5 6.6 6.6 56.645 156,769 156,755 156,649 156,734 156,904 1 51 53 40 50 42 42 42 268 175 78 10 0 0 0 0 473.0 329.0 147.0 15.0 0 0 0 0 0	Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Mar Apr Jun Jul Aug Sep Col. 10 50.0 35.8 18.6 9.4 6.5 6.6 6.6 10.2 156,645 156,769 156,769 156,789 156,794 156,794 157,395 157,395 51 53 40 50 42 42 46 65 268 175 78 10 0 0 0 18 473.0 329.0 147.0 15.0 0.0 0 0 18	Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Col. 10 Col. 11 Col. 12 Col. 12 Col.		Col. 1	Jan	52.1	156,317	333	51	283	522.0				
					2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Apr May Jun Jul Aug Sep 35.8 18.6 9.4 6.5 6.6 6.6 6.6 156,769 156,769 156,594 156,743 156,904 1 53 40 50 42 42 42 175 78 10 0 0 0 329.0 147.0 15.0 0.0 0 0	2018 BUDGGT - VOLUME, CUSTOMERS & AVERAGGE USE Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Apr May Jun Jul Aug Sep Col. 10 35.8 18.6 9.4 6.5 6.6 6.6 10.2 156,769 156,769 156,649 156,594 156,743 156,904 157,395 238 119 60 42 42 42 65 53 40 50 42 42 46 175 78 10 0 0 18 329:0 147:0 15.0 0 0 55.0	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Col. 11 Apr May Jun Jul Aug Sep Oct Nov 35.8 18.6 9.4 6.5 6.6 6.6 10.2 21.8 156,769 156,769 156,649 156,743 156,904 157,395 157,840 157,840 228 119 60 42 42 42 65 138 53 40 50 42 42 46 51 175 78 10 0 0 18 87 329.0 147.0 15.0 0.0 0 55.0 211.0		Col. 2	Feb	55.9	156,488	357	49	308	260.0
2018 BUDGET - V Col. 4 Col. 5 Apr May 35.8 18.6 156,769 156,755 53 40 175 78 329.0 147.0	2018 BUDGET - VOLUME, Oct. 6 Apr. May Jun 35.8 18.6 9.4 156,769 156,755 156,649 53 40 50 175 78 10	2018 BUDGET - VOLUME, CUSTOMI Col. 4 Col. 5 Col. 6 Col. 7 Apr	2018 BUDGET - VOLUME, CUSTOMERS & AVI 2018 BUDGET - VOLUME, CUSTOMERS & AVI Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Apr May Jun Jul Aug 35.8 18.6 9.4 6.5 6.6 156,769 156,755 156,649 156,594 156,743 53 40 50 42 42 175 78 10 0 0 329.0 147.0 15.0 0.0 0.0	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE US 2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE US Col. 4 Col. 5 Col. 6 Col. 9 Col. 9 Abr Iun Jul Aug Sep 35.8 18.6 9.4 6.5 6.6 6.6 156,769 156,755 156,649 156,734 156,904 42 42 53 40 50 42 42 42 42 175 78 10 0 0 0 0 339.0 147.0 15.0 0.0 0.0 0.0 0	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE 2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 4 Col. 5 Col. 6 Col. 10 Col. 10 Col. 10 Abr May Jun Jul Aug Sep Col. 10 35.8 18.6 9.4 6.5 6.6 6.6 10.2 156,769 156,755 156,649 156,794 156,743 156,904 157,395 23 40 50 42 42 42 46 175 78 10 0 0 0 18 339.0 147.0 15.0 0.0 0 0 55.0	Col. 10 10.2 10.2 57,395 18 25.0	Col. 10 Col. 11 Oct Nov 10.2 21.8 57,395 157,840 3 46 51 18 87 55.0 211.0		Col. 3	Mar	50.0	156,645	319	51	268	473.0
119 119 78 78	DGET - VOLUME, Col. 6 May Jun 18.6 9.4 156,755 156,649 40 50 78 10	DGET - VOLUME, CUSTOMI Col. 5	DGET - VOLUME, CUSTOMERS & AVI Col. 5 Col. 6 Col. 7 Col. 8 May Jun Jul Aug 18.6 9.4 6.5 6.6 156,755 156,649 156,594 156,743 40 50 42 42 78 10 0 0 0	May Jun Jul Aug Sep 156,755 156,649 156,594 156,742 42 42 78 10 0 0 0 0 0 147.0 156 65 66 66 66 66 66 156,755 156,649 156,594 156,743 156,904 42 42 42 140 50 42 42 42 42 42 42 147.0 15.0 0.0 0.0 0.0 0.0 0.0	DGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 5 Col. 6 Col. 9 Col. 10	Col. 10 10.2 10.2 57,395 18 25.0	Col. 10 Col. 11 Oct Nov 10.2 21.8 57,395 157,840 3 46 51 18 87 55.0 211.0	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE Col. 1 Col. 2 Col. 3 Col. 4 Col. 5 Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Col. 11 Col. 13 Budget Volumes 52.1 55.9 50.0 35.8 18.6 9.4 6.5 6.6 6.6 10.2 21.8 37.8 311.5 Customer Meters 156,317 156,488 156,645 156,759 156,755 156,649 156,734 156,748 156,904 157,395 157,840 158,209 156,942		228	23	175	329.0			
	Col. 6 Lun 144 156,649 10 110	Col. 6 Col. 7 Jun Jul 156,649 156,594 50 42 50 42 115.0 0.0	201. G Col. 7 Col. 8 1un 1ul Aug 9.4 6.5 6.6 60 42 42 50 42 42 150 0 0 0	156,649	Col. 6 Col. 7 Col. 8 Col. 9 Col. 10 Jun Jul Aug Sep Oct 9.4 6.5 6.6 6.6 10.2 156,649 156,594 156,743 156,904 157,395 50 42 42 42 46 10 0 0 18 46 150 0 0 18 18 150 0 0 0 18 150 0 0 0 550	Col. 10 Oct 10.2 57,395 18 55.0	Col. 10 Col. 11 Oct Nov 10.2 21.8 57,395 157,840 3 46 51 18 87 55.0 211.0	DGET - V	Budget Volumes 52.1 55.9 50.0 35.8 18.6 9.4 6.5 6.6 6.6 6.6 10.2 21.8 23.9 11.9 60.4 42.7 60.6 60.1	40	78	147.0				
Col. 10 Col. 11 Col. 12 Oct Nov Dec 10.2 21.8 37.8 57,395 157,840 158,209 65 138 239 46 51 45 18 87 194 55.0 211.0 379.0	Col. 10 Col. 11 Col. 12 Oct Nov Dec 10.2 21.8 37.8 57,395 157,840 158,209 65 138 239 46 51 45 18 87 194 55.0 211.0 379.0	Col. 10 Col. 11 Col. 12 Oct Nov Dec 10.2 21.8 37.8 57,395 157,840 158,209 65 138 239 46 51 45 18 87 194 55.0 211.0 379.0	Col. 10 Col. 11 Col. 12 Oct Nov Dec 10.2 21.8 37.8 57,395 157,840 158,209 65 138 239 46 51 45 18 87 194 55.0 211.0 379.0	Col. 12 Dec 37.8 37.8 239 45	· ·	Col. 13 Total 311.5 312.5,942 1,985 1,422 2,691.0				Notes			Row 1.1 / Row 1.2			

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.8 Page 8 of 14

TABLE 7	GENERAL SERVICE RATE 6, METRO REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BUI	DGET - VO	OLUME, C	USTOME	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	RAGE US	ΨĮ				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	Jun	<u>lnr</u>	Aug	Sep	0ct	Nov	Dec	Total	Notes
1.1	Budget Volumes (10 ⁶ m³)	313.0	367.1	319.5	234.7	143.3	73.9	50.8	48.5	47.0	76.8	167.9	248.8	2,091.3	
1.2	Customer Meters Budget	53,500	53,606	53,703	53,566	53,263	52,498	52,193	51,834	51,746	52,362	53,171	53,602	52,920	
1.3	Budget Average Use per Customer (m³)	5,850	6,849	5,950	4,381	2,691	1,407	973	936	806	1,467	3,157	4,642	39,211	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m³)	1,546	1,714	1,602	1,349	1,325	1,311	973	936	806	864	1,262	1,409	15,199	
1.5	Heatload Average Use per Customer (m³)	4,304	5,134	4,348	3,032	1,366	96	0	0	0	604	1,895	3,233	24,012	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

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TABLE 8	GENERAL SERVICE RATE 6, WESTERN REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BU	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	OLUME, C	CUSTOME	RS & AVE	ERAGE US	뗐				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	May	<u>Jun</u>	미	Aug	Sep	<u>Oct</u>	Nov	Dec	Total	Notes
1.1	Budget Volumes (10 ⁶ m³)	130.1	157.2	128.7	93.9	56.4	25.8	18.4	18.3	18.4	26.6	64.9	106.0	844.6	
1.2	Customer Meters Budget	30,858	30,897	30,932	30,887	30,787	30,533	30,435	30,312	30,289	30,496	30,765	30,916	30,676	
1.3	Budget Average Use per Customer (m³)	4,215	5,088	4,162	3,039	1,831	844	909	909	809	872	2,108	3,429	27,405	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m³)	951	972	931	785	823	751	909	909	809	563	852	1,022	9,470	
1.5	Heatload Average Use per Customer (m³)	3,264	4,115	3,231	2,254	1,007	93	0	0	0	308	1,256	2,407	17,936	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.8 Page 10 of 14

TABLE 9	GENERAL SERVICE RATE 6, CENTRAL REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	OGET - VC	OLUME, C	USTOME	RS & AVE	RAGE US	Ш				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		<u>Jan</u>	Feb	Mar	Apr	Мау	<u>lun</u>	미	Aug	Sep	Oct	Nov	Dec	Total	Notes
1.1	Budget Volumes (10 ⁶ m³)	45.3	57.8	47.6	34.0	19.0	9.0	9.9	6.9	7.7	13.7	26.6	37.0	311.2	
1.2	Customer Meters Budget	13,491	13,508	13,526	13,497	13,445	13,310	13,258	13,192	13,178	13,288	13,429	13,502	13,385	
1.3	Budget Average Use per Customer (m³)	3,358	4,277	3,519	2,521	1,410	629	496	522	285	1,030	1,983	2,740	23,120	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	1,511	1,891	1,648	1,245	929	288	496	522	585	761	1,066	1,381	12,373	
1.5	Heatload Average Use per Customer (m^3)	1,847	2,385	1,871	1,276	734	06	0	0	0	268	917	1,358	10,747	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.8 Page 11 of 14

TABLE 10	GENERAL SERVICE RATE 6, NORTHERN REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		<u>Jan</u>	Feb	Mar	Apr	May	<u>Jun</u>	<u>lnr</u>	Aug	Sep	<u>Oct</u>	Nov	Dec	Total	<u>Notes</u>
1.1	Budget Volumes (10 ⁶ m³)	109.0	124.8	107.6	76.6	42.6	19.6	15.6	14.8	15.6	26.6	56.0	87.5	696.4	
1.2	Customer Meters Budget	36,844	36,876	36,909	36,871	36,782	36,558	36,474	36,368	36,348	36,527	36,762	36,896	36,685	
1.3	Budget Average Use per Customer (m³)	2,960	3,383	2,916	2,078	1,157	537	427	408	430	728	1,524	2,370	18,918	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	829	926	877	683	581	450	427	408	430	471	630	784	7,526	
1.5	Heatload Average Use per Customer (m³)	2,101	2,457	2,040	1,395	576	87	0	0	0	257	894	1,586	11,393	
	Meter Reading BP DD (Central)	552.0	583.0	475.0	326.0	132.0	11.0	0.0	0.0	0.0	65.0	232.0	406.0	2,782.0	

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.8 Page 12 of 14

TABLE 11	GENERAL SERVICE RATE 6, EASTERN REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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					2018 BUD	OGET - VO	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE	USTOME	RS & AVE	-RAGE US	ايد				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		Jan	Feb	Mar	Apr	Мау	<u>lul</u>	피	Ang	Sep	<u>Oct</u>	Nov	Dec	Total	Notes
1:1	Budget Volumes (10 ⁶ m³)	89.0	112.2	92.0	67.5	35.9	17.0	12.0	11.7	12.0	21.5	47.9	74.2	592.7	
1.2	Customer Meters Budget	22,450	22,482	22,515	22,465	22,361	22,102	22,002	21,876	21,850	22,054	22,321	22,460	22,245	
1.3	Budget Average Use per Customer (m³)	3,963	4,991	4,084	3,004	1,604	768	547	534	549	926	2,145	3,303	26,467	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	871	1,012	837	608	745	982	547	534	547	652	729	856	8,824	
1.5	Heatload Average Use per Customer (m³)	3,092	3,980	3,247	2,195	829	83	0	0	2	323	1,415	2,446	17,643	
	Meter Reading BP DD (Eastern)	696.0	716.0	568.0	381.0	147.0	9.0	0.0	0.0	2.0	86.0	288.0	494.0	3,387.0	

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.BOMA.8 Page 13 of 14

TABLE 12	GENERAL SERVICE RATE 6, NIAGARA REGION	2018 BUDGET - VOLUME, CUSTOMERS & AVERAGE USE
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		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	9.loo	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	
Item.		<u>Jan</u>	Feb	Mar	Apr	Мау	<u>lun</u>	lu[Aug	Sep	0ct	Nov	Dec	Total	Notes
1.1	Budget Volumes (10 ⁶ m³)	43.0	51.0	45.4	34.0	19.5	10.5	7.5	7.4	7.9	12.0	22.3	33.1	293.5	
1.2	Customer Meters Budget	11,750	11,770	11,786	11,763	11,710	11,577	11,527	11,462	11,450	11,560	11,705	11,782	11,654	
1.3	Budget Average Use per Customer (m^3)	3,661	4,329	3,851	2,892	1,669	911	649	648	289	1,034	1,901	2,808	25,040	Row 1.1 / Row 1.2
1.4	Baseload Average Use per Customer (m^3)	819	895	845	749	884	774	649	648	289	570	644	720	8,885	
1.5	Heatload Average Use per Customer (m^3)	2,842	3,434	3,006	2,143	785	137	0	0	0	463	1,257	2,088	16,155	
	Meter Reading BP DD (Niagara)	522.0	560.0	473.0	329.0	147.0	15.0	0.0	0.0	0.0	55.0	211.0	379.0	2,691.0	

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- d) No, the balance point degree days do not vary for different groupings other than the three weather zones.
- e) No, EGD hasn't made empirical studies of the influence of higher or lower gas prices on demand, in addition to the results supplied by the econometric model.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.CCC.4 Page 1 of 1

CCC INTERROGATORY #4

INTERROGATORY

(Ex. C1/T1/S1/p. 3)

Please provide the forecast and actual Other Operating Revenues and Other Income for each year 2013-2017.

RESPONSE

The Board approved the forecast Other Operating Revenue and Other Income for each of the years 2014 to 2018 in the EB-2012-0459 Custom IR proceeding (July 17, 2017 Decision at page 28). Actual utility results are presented and reviewed within each fiscal year's annual ESM and deferral and variance account review applications.

Witness: K. Culbert

Exhibit I.C1.EGDI.CCC.5

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CCC INTERROGATORY #5

INTERROGATORY

(Ex. C1/T2/S1/p. 5)

The evidence states that regression model results for Rate 1 and Rate 6 are adjusted for planned DSM in the test year through partially-effective volumetric savings by program. Please explain, in detail, the process EGD undertakes to derive these adjustments. What programs do the 2018 adjustments relate to?

RESPONSE

Following the derivation of average uses by revenue class and region using regression models as described at Exhibit CS, Tab 2, Schedule 1, DSM forecast savings are subtracted from the resulting average use baseline forecasts to account for incremental DSM programs in 2018 not otherwise inherent in historical average use.

Partially effective annual DSM volumetric savings are used to reflect the forecast DSM savings for any given year, recognizing that DSM program participants will be added at different times during the year. (Fully effective DSM savings would only apply if all programs and participants were delivered and fully subscribed on January 1st of the program year.) Partially effective DSM savings are calculated by dividing 75% of the annual savings equally by month, assuming savings accumulate at the same rate monthly. For specificity, partially effective volumes in January represent 1/12 of the savings; for February, year-to-date DSM savings represent 2/12 of the savings from January, plus 1 / 12 of the new savings in February, and so on. Total partially-effective volumes per unlocked customer are subtracted from the average use forecast per unlocked customer at the revenue class level for Rates 1 and 6.

The DSM results reflected in the 2018 forecast as noted in the 2015 to 2020 Multi-Year DSM Plan (EB-2015-0049), include the following offers:

Rate 1	Rate 6
ivaic i	naic o

Home Energy Conservation Adaptive Thermostat Low Income Winter Proofing Commercial & Industrial Custom Commercial & Industrial Prescriptive Run it Right Direct Install Low-Income MR Affordable Housing

Witnesses: E. Reimer

M. Suarez

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.EP.5

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EP INTERROGATORY #5

INTERROGATORY

References: Exhibit C1 Tab 2 Schedule 1 Appendix A

Exhibit C2 Tab1 Schedule 3 Table 5

- A). Please discuss why EGD is relying on the Average Use model to predict that the declining use trend of prior years will continue in 2017/18.
- B). The NAC Forecast for 2018 is ~100m³ lower than 2017F. Please discuss in more detail why/how dummy variables were introduced (based on the Chow Test) for Class 20 Metro and Eastern Zone Class 73, but not other zones and why a DUM 2016 of 0.04 was chosen and why resulting 2018 forecast is credible.
- C). Please provide an estimate the impact of a 10 m³ change in residential Normalized Average Use on each of: the 2018 volume forecast; revenue forecast and revenue requirement. Provide references to filed schedules.

RESPONSE

- A) The Company's average use models rely on historical data and given the historical trend, in the absence of any other development that would reverse the trend, the expectation is that the declining trend will continue. Every statistical test that has been run on the models continues to indicate that the models are good predictors of average use. Residential average use has continued to decline consistently since the Energy Efficiency Act prohibited selling of the conventional low-efficiency furnace in January 1992. Energy efficiency gains in new construction, the turnover in stock to higher efficiency gas furnaces and appliances, utilities' Demand Side Management ("DSM") programs, high commodity prices between 2001 and 2008 and a global economic slowdown since 2009 have resulted in a significant decrease in the residential average use over the 20 year period (1993 to 2016). On a weather-adjusted basis, residential average use fell from 3,196 m³ in 1993 to 2,509 m³ in 2015 and to 2,410 m³ in 2016 (more than 20 percent). The Ontario Government's efforts to cut its greenhouse gas emissions 15% by the end of 2020, 37% by the end of 2030, and 80% below 1990 levels by 2050 also supports the Company's declining average use trend expectation.
- B) The change in average use for 2018 as calculated in Exhibit C1,Tab 2, Schedule 1 Appendix A, Table 3, page 4, Column 12 is the percentage change from the 2017 Board Approved Budget shown in Column 11. The 2017 Board Approved Budget was

Witnesses: H. Sayyan

M. Suarez

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developed in an earlier proceeding using the actuals to 2015 and the assumptions from 2016 Spring Economic Outlook while the 2018 forecast is developed using the actuals to 2016 and the assumptions from 2017 Winter Economic Outlook. As a result, the decrease of 101 m³ in 2018 is not reflective of the average use trend.

Regarding the introduction of a dummy variable for 2016, please see the response to Board Staff Interrogatory #6, at I.C2.EGDI.STAFF.6. As noted in that response and in Exhibit C2, Tab 1, Schedule 3, besides testing forecast accuracy, the models were subjected to a battery of diagnostic tests. These tests were run on the model to check for incorrect functional forms, parameter instability, structural breaks, omitted variables and randomness of residuals. Diagnostic tests indicated the existence of a structural break only for the Revenue Class 20-Metro and the Revenue Class 73-Eastern models. To suppress the likelihood of a similar off-trend result in 2016 being forecast, the Company included dummy variables in those models by assuming that this specific 2016 data was an outlier.

Without controlling for the 2016 outlier through a dummy variable, the Rate 1 average use forecast would have been 2.4 m³ lower than proposed.

C) A change in forecast residential average use by 10 m³ would have an impact on the 2018 volume forecast by approximately 20.0 10⁶m³.

Note that the change in forecast volume does not impact / change the forecast 2018 distribution revenue requirement.

The impacts of such a change in the volume forecast on delivery revenue at existing rates (EB-2017-0181 rates) and the 2018 revenue deficiency (Exhibit F1, Tab 1, Schedule 1, page 3) would be approximately \$1.5 million.

Witnesses: H. Sayyan M. Suarez

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.FRPO.1 Page 1 of 1

FRPO INTERROGATORY #1

INTERROGATORY

REF: Exhibit C1, Tab 1, Schedule 1, Page 3, paragraph 9

Preamble: We would like to understand better the basis for the updates to the Transmission, Compression and Storage revenues. The reference states: "Transmission, Compression and Storage revenues for the 2018 Updated Forecast are also developed on the basis of Final Rate Order in EB-2014-0276..."

- 1) Please confirm or correct the basis for Transmission, Compression and Storage as being EB-2014-0276.
 - a) If correct, please explain why a more up-to-date basis is not used.

RESPONSE

The referenced evidence included an incorrect reference to EB-2014-0276, Enbridge's 2015 Rate Adjustment Proceeding. The correct reference is the EB-2016-0215 Final Rate Order, from Enbridge's 2017 Rate Adjustment Proceeding, and the subsequent July 1, 2017 EB-2017-0181 QRAM proceeding.

Witnesses: R. Small M. Suarez

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FRPO INTERROGATORY #2

INTERROGATORY

REF: Exhibit C1, Tab 2, Schedule 1, Figures 2 and 3

Preamble: Absent similar actual observations, we understand that 2016 actuals are anomalous, we would like to explore the impact of a simpler approach to forecasting the Normalized Average Use for the general rate classes. Page 8-9 of Schedule states: "average use decline in 2016 was an anomaly as it was not consistent with the historical trend, declining from 2015 by -3.2%. No significant development occurred in 2016 that would allow direct causal inference with 2016 results. As a result, the Company is inclined to treat the 2016 experience as an anomaly until additional, similar actual observations constitute an indication of trend."

Please produce a linear regression extrapolation of the Actual Average Use values in Figure 2 from to 2007 to 2015 to project a forecasted value for 2018.

a) Please provide the resulting rate impact of using the linear regression forecast value as compared to the econometric value of 2,363.

RESPONSE

The Company's average use methodology was first proposed and approved in RP-2000-0040 and has since been applied consistently for volumetric forecasting in the Company's Rate Applications. The approved methodology (which are linear regression models) utilizes long term historical data and the relationships between average use and the driver variables, as described in Exhibit C2 Tab1 Schedule 3, to derive average use forecasts. The statistical tests conducted on the regression models indicate that the driver variables included in each model have an impact on average use.

Figure 2 shows the trend of normalized residential average use for illustration purposes only. The Company believes that it is necessary to utilize a full sample of the data available to it when estimating the average use models and thus deriving the volumetric forecast. For the 2018 forecast, actual data from 1985 up to and including 2016 were utilized.

Enbridge interprets FRPO's request in this interrogatory as follows: To utilize the actual normalized average use presented in Figures 2 & 3 as the dependent variable (excluding 2016 in the sample), to insert a trendline through these data and to use this trendline to

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project an average use value for 2018.

It is the Company's position that excluding the latest available actual data or shortening the sample period is not appropriate. The methodology suggested by FRPO is a significant departure from the approved forecasting method currently used by Enbridge and has not been tested. Further, a simple trend does not capture the impacts of the driver variables that have been shown to impact average uses (degree days, gas prices etc...).

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FRPO INTERROGATORY #3

INTERROGATORY

REF: Exhibit C1, Tab 2, Schedule 1, Figures 2 and 3

Preamble: Absent similar actual observations, we understand that 2016 actuals are anomalous, we would like to explore the impact of a simpler approach to forecasting the Normalized Average Use for the general rate classes. Page 8-9 of Schedule states: "average use decline in 2016 was an anomaly as it was not consistent with the historical trend, declining from 2015 by -3.2%. No significant development occurred in 2016 that would allow direct causal inference with 2016 results. As a result, the Company is inclined to treat the 2016 experience as an anomaly until additional, similar actual observations constitute an indication of trend."

Please produce a linear regression extrapolation of the Actual Average Use values in Figure 3 from to 2007 to 2015 to project a forecasted value for 2018.

a) Please provide the resulting rate impact of using the linear regression forecast value as compared to the econometric value of 28,656.

RESPONSE

Please see response to FRPO Interrogatory #2 found at Exhibit I.C1.EGDI.FRPO.2.

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IGUA INTERROGATORY #1

INTERROGATORY

Reference: Exhibit C1, Tab 2, Schedule 1, Appendix C, Page 2

EGD notes that the impact of Cap and Trade was captured within the regression models through the gas price variable as an addition to the commodity, load balancing, and distribution components of Rate 1 gas prices and Rate 6 gas prices.

(a) What was the amount of the cap and trade obligation that EGD used for modelling purposes and why?

RESPONSE

(a) Please see response to SEC Interrogatory #2 at Exhibit I.C1.EGDI.SEC.2.

Exhibit I.C1.EGDI.IGUA.2

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IGUA INTERROGATORY #2

INTERROGATORY

Reference: Exhibit C1, Tab 2, Schedule 1, Appendix C, Page 3

EGD notes that for 2018 Contract Market forecasts, account executives have engaged large volume customers in assessing their individual participation in Cap and Trade as well as how they may be pursuing abatement that would result in operational changes. The resulting grassroots forecast includes large volume customer's considerations of the impact of Cap and Trade.

- (a) Is this the first year that EGD has included large volume customers' considerations of the impact of Cap and Trade on EGD's Contract Market forecasts in developing its volume forecasts?
- (b) What does EGD believe the impact on its Contract Market forecasts will be, if any, in terms of forecast error by virtue of the inclusion of large volume customers' considerations of the impact of Cap and Trade? (see comment made in Exhibit C1, Tab 2, Schedule 1, Appendix C, Page 2 of 4, paragraph 5)

RESPONSE

- No, 2017 was the first year the Company included large volume customers' considerations of the impact of Cap and Trade when developing its volume forecasts.
- b) As noted in paragraph 5 of Exhibit C1, Tab 2, Schedule 1, Appendix C, the grass root contract volume forecast for 2018 considers current economic conditions and industrial factors which would include the impact of Cap and Trade. Contract Market volumes are primarily driven by economic factors, and other economic factors, such as unexpected changes in gas prices or unexpected appreciation of the U.S dollar, which could contribute to a forecast variance in Contract Market volumes. However, with respect to the impact of Cap and Trade, the Company does not anticipate major changes in demand from Contract Market customers in 2018 when comparing the 2018 Contract Market volume forecast with the 2017 Board-Approved.

Exhibit I.C1.EGDI.SEC.1

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SEC INTERROGATORY #1

<u>INTERROGATORY</u>

[C1-2-1, p.7]

Please provide a table showing for each year between 2013 and 2017, the Board approved contract market unlocks and actual contract market actuals.

RESPONSE

The following table shows the Actual and Board-Approved number of contract market customers for the years from 2013 to 2017.

NUMBER OF CONTRACT MARKET CUSTOMERS

<u>YEAR</u>	<u>ACTUAL</u>	BOARD-APPROVED	<u>Variance</u>
2013	412	424	(12)
2014	394	404	(10)
2015	384	381	3
2016	416	376	40
2017		410	

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.SEC.2 Page 1 of 1

SEC INTERROGATORY #2

INTERROGATORY

[C1-2-1, App C]

With respect to the cap and trade impact on 2018 volume forecast, please provide the specific 2018 cap and trade charges that Enbridge used to model the impact on the volume forecast.

RESPONSE

Cap and Trade charges of 3.35 cents / m³ in 2017, and 3.59 cents/m³ in 2018 were used to model the impact of Cap and Trade on the volume forecast. The 2018 forecast was produced assuming the auction reserve price will increase by 5% plus inflation over 2017 as stated in 'Implementation of Ontario's cap and trade program and the regulator's role' by the OEB, on July 21, 2016; slide #17.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.VECC.1 Page 1 of 1

INTERROGATORY

Reference: Exhibit C1/T2/S1/pg. 8

a) How was the general service forecast methodology adjusted for the known migration of the Rate 125 power generation customer (8.1 106m3) to General Service?

VECC INTERROGATORY #1

RESPONSE

The volumetric impact related to the migration of the Rate 125 customer to general service was added to the overall general service Rate 6 volume forecast as an incremental adjustment on top of Rate 6 baseline average use volumes.

Exhibit I.C1.EGDI.VECC.2

Page 1 of 1

VECC INTERROGATORY #2

<u>INTERROGATORY</u>

Reference: Exhibit C1/T2/S1/pg. 13

a) How is normalized average use for Rate 6 adjusted for the forecast migration of Contract customers?

RESPONSE

Results using the average use forecast methodology described at Exhibit C2 Tab1 Schedule 3 form the baseline forecast for Rate 1 and Rate 6 volumes. Where migration of contract customers occurs, associated forecast volumes are layered onto the normalized baseline Rate 6 volumetric forecast and removed from the originating contract rate volumes. Rate 6 average use volumes are then recalculated with the incremental volumes and incremental unlocks from migration. No additional normalization is carried out as contract market volumetric forecasts are already normalized.

The forecasted customer migration from Contract rates has increased the overall Rate 6 volumes and subsequently increased the normalized average use for Rate 6. As shown in Exhibit C3, Tab 2, Schedule 3, page 3, Columns 7 and 8, the net customer migration from Contract rates (column 7 plus column 8) has increased the overall Rate 6 volumes by 22.6 10^6m^3 . The impact on normalized average use for Rate 6 is about 135 m³.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C1.EGDI.VECC.3

Page 1 of 1

VECC INTERROGATORY #3

INTERROGATORY

Reference: Exhibit C1/T2/S1/pg. 14

- a) In what year was the EBO 487 decision on using "balance point" adjustment to degree days?
- b) Directionally what is effect on normalized average use of this adjustment as compared to using 180 degrees?

<u>RESPONSE</u>

- a) The OEB decision on EBO 487 was for the 1995 Rate Application.
- b) There is no impact. Please see response to BOMA Interrogatory # 7 at Exhibit 1.C1.EGDI.BOMA.7.

Exhibit I.C2.EGDI.STAFF.6

Page 1 of 3

BOARD STAFF INTERROGATORY #6

INTERROGATORY

Ref: Operating Revenues – Average Use Forecasting Model Exhibit C2 / Tab 1 / Schedule 3 / Pages 9-10

Preamble:

Enbridge noted that diagnostic test results show that the models are statistically valid and no assumptions appear to be violated at the 95% confidence level except the 'No structural change' assumption for Metro region revenue class 20 (Rate 1) and Eastern region revenue class 73 models. The Chow forecast test result for those two models has indicated the existence of structural change in 2016. Dummy variables have been introduced to those models to correct this.

Question(s):

- a) Please provide additional rationale supporting Enbridge's proposal to include a dummy variable in its average use models to address the structural change in 2016.
- b) Please advise whether Enbridge has previously introduced a dummy variable in its average use models to address structural changes? If so, please provide the years for which a dummy variable was included and advise whether the OEB approved the use of the dummy variable.
- c) Please provide the 2018 average use forecast for Rates 1 and 6 removing the dummy variable designed to correct for the 2016 structural change from the average use model. Please also provide a comparison of OEB staff's requested revised average use forecast and Enbridge's proposed average use forecast.

RESPONSE

a) The use of dummy variables is standard practice in regression estimation particularly where structural breaks and/or outliers are indicated, or when observations within a time series serve to break off well-established trends. A dummy variable serves to nullify that observation, effectively excluding the "noise" from the estimation in order to obtain more reliable results.

Witnesses: H. Sayyan

M. Suarez

Exhibit I.C2.EGDI.STAFF.6

Page 2 of 3

As described in Exhibit C2, Tab1, Schedule 3, page 7, diagnostic tests are run on the models to check for incorrect functional forms, parameter instability, structural breaks, omitted variables, and randomness of residuals. Where models fail the diagnostic tests, model modifications are made to ensure the results can be interpreted with confidence. Test results are shown in Tables 6 and 9 for transparency.

Within the average use methodology which has been in place since 2000, dummy variables have been used where diagnostic testing has indicated it appropriate to do so. The Chow Test assesses whether a structural break has occurred. Those breaks can be outliers, level-shifts, or temporary changes. The average use models are corrected in response to a structural break through the inclusion of a dummy variable. Previously, dummy variables have been used to account for recessionary periods and migration impacts over the years. Driver variables have been listed in Tables 4 and 7 of the Average Use Methodology evidence (Exhibit C2, Tab 2, Schedule 1 of each proceeding), with all average use models and corresponding results in Tables 5 and 8. Dummy variables have been shown in these tables and results where they were utilized in the models.

The Company has always maintained that continuous model evaluation ensures that ongoing impacts in the relationship of average use and its driver variables is captured to produce the most accurate and objective forecast as possible. The use of dummy variables is a standard tool that has proven useful in objectively controlling for structural breaks and/or outliers in the data.

b) Given the timelines for EGD, can confirm that dummy variables were used since the 2010 Test year to account for a structural change in 2008 actual results from the recession. For some models, multiple dummy variables were included to control for recessionary impacts in multiple years. For Rate 6 models, dummy variables were included to account for both recession and migration impacts (from contract classes).

The Company's average use methodology was first proposed and approved in RP-2000-0040 and has since been the established methodology applied for average use volumetric forecasting. All variables, model results, and diagnostic testing results have been included in the Average Use Methodology evidence typically shown at Exhibit C2 Tab 1 as part of Rate applications. The OEB has approved average use forecasts and/or volume forecasts inclusive of average uses for each of those years.

c) As shown in the following table, If dummy variables were not included to control for 2016 average uses in Rate 1 and Rate 6, the 2018 average use forecasts would have been 2.4 m³ and 0.2 m³ lower, respectively. The total volumetric impact of not controlling for the 2016 break would have been an additional volumetric reduction of approximately 4.8 million m³.

Witnesses: H. Sayyan

M. Suarez

Exhibit I.C2.EGDI.STAFF.6

Page 3 of 3

2018 Average use (m3)	Rate 1	Rate 6
Proposed Models (with dummy)	2,363.0	28,656.0
Requested (excludes DUM 2016)	2,360.6	28,655.8
Difference in Average use (m ³)	(2.4)	(0.2)
Total Volumetric impact (m ³)	(4,755,767)	(34,863)

Witnesses: H. Sayyan M. Suarez

Exhibit I.C2.EGDI.BOMA.9

Page 1 of 2

BOMA INTERROGATORY #9

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 1

Can EGD update the Economic Outlook to 2017 Q3 Economic Outlook?

RESPONSE

Please see the updated Canada, U.S. and Ontario economic assumptions as reflected in the Q3 2017 Economic Outlook. Due to the time and effort required, the Company has not updated the Regional economic assumptions for Q3 2017.

Economic Outlook

CANADA & U.S.

CALENDAR YEAR	2012	2013	2014	2015	2016	2017F	2018F
REAL GDP (% CHANGE)							
CANADA	1.6	2.3	2.6	0.8	1.4	3.1	2.2
U.S.	2.2	1.7	2.4	2.6	1.6	2.2	2.4
CANADA REAL EXPORTS (% CHANGE)	2.9	2.0	5.3	3.6	1.4	2.3	2.8
CANADA REAL IMPORTS (% CHANGE)	4.2	1.9	2.0	1.0	-0.9	3.5	2.5
CANADA HOUSING STARTS (000's)	214.8	187.9	189.3	195.5	197.9	213.6	193.4
CANADA UNEMPLOYMENT RATE (%)	7.4	7.1	6.9	6.9	7.0	6.4	6.2
CANADA EMPLOYMENT GROWTH (% CHANGE)	1.4	1.3	0.6	0.8	0.7	1.6	1.0
CONSUMER PRICES (% CHANGE)							
CANADA	1.6	0.9	1.9	1.1	1.4	1.5	1.8
U.S.	2.1	1.5	1.6	0.1	1.3	2.1	2.0

Exhibit I.C2.EGDI.BOMA.9

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Economic Outlook

ONTARIO

CALENDAR YEAR	2012	2013	2014	2015	2016	2017F	2018F
REAL GDP (% CHANGE)	1.3	1.5	2.7	2.5	2.6	3.0	2.2
REAL MANUFACTURING OUTPUT (% CHANGE)	2.0	-1.2	3.7	1.5	4.0	1.0	1.7
HOUSING STARTS (000's)	76.7	61.1	59.1	70.2	75.0	78.3	70.2
UNEMPLOYMENT RATE (%)	7.9	7.6	7.3	6.8	6.6	6.2	6.0
EMPLOYMENT GROWTH (% CHANGE)	0.7	1.8	0.8	0.7	1.1	1.4	1.1
CONSUMER PRICES (% CHANGE)	1.4	1.1	2.3	1.2	1.8	1.6	1.8
RETAIL SALES (% CHANGE)	1.6	2.3	5.0	4.2	4.7	6.5	3.7
WAGE RATE (% CHANGE)	2.2	0.9	2.5	2.7	4.0	2.9	2.6
REAL RESIDENTIAL NATURAL GAS PRICE (% CHANGE)	-9.4	4.8	3.8	-5.5	-7.7	12.2	-0.5
REAL COMMERCIAL NATURAL GAS PRICE (% CHANGE)	-12.0	6.8	5.8	-6.1	-10.5	15.7	-0.3

Exhibit I.C2.EGDI.BOMA.10

Page 1 of 1

BOMA INTERROGATORY #10

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 2, p10, Conversion of Degree Days

Please explain why the actual Environment Canada degree days and the Gas Supply degree days bear no constant relationship to one another over the multiyear period, and in the 2018 Forecast at Table 10, p10.

RESPONSE

Gas Supply and Environment Canada determine daily average temperature using different methods. Gas Control determines its daily average temperature by using the average temperature over a 24-hour period. Environment Canada determines its daily average temperature by averaging the daily minimum and maximum temperatures over a 24-hour period.

Although Environment Canada degree days differ slightly from Gas Supply degree days in how they are recorded, they are highly correlated with one another (but no constant relationship). Since the Company sets its volumes budget using Gas Supply degree days but the Board-approved methods require the longer data history supplied by Environment Canada, the Environment Canada degree day forecast is transformed to Gas Supply degree day forecast by regressing actual Gas Supply degree days onto actual Environment Canada degree days as outlined at EB-2017-0086, Exhibit C2, Tab 1, Schedule 2, pages 8 to 10, Tables 7 to 9.

Witness: M. Suarez

H. Sayyan

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C2.EGDI.BOMA.11 Page 1 of 1 Plus Attachments

BOMA INTERROGATORY #11

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 3, p3

Please provide a copy of the cited AGA Forecasting Review, and of each of the articles in footnotes 2 and 3.

RESPONSE

Attached are the first two articles referenced in footnotes 2 and 3 in Exhibit C2, Tab 1, Schedule 3, page 3. The Company has not been able to access the third article published in the AGA Forecasting Review: American Gas Association. Note that efforts were made to locate this article including contacting the AGA, and the author Anthony E. Bopp directly, however, this has not proven successful. At this time it is unlikely the article will be located.



Co-Integration and Error Correction: Representation, Estimation, and Testing

Robert F. Engle; C. W. J. Granger

Econometrica, Vol. 55, No. 2. (Mar., 1987), pp. 251-276.

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Econometrica, Vol. 55, No. 2 (March, 1987), 251-276

CO-INTEGRATION AND ERROR CORRECTION: REPRESENTATION, ESTIMATION, AND TESTING

By Robert F. Engle and C. W. J. Granger¹

The relationship between co-integration and error correction models, first suggested in Granger (1981), is here extended and used to develop estimation procedures, tests, and empirical examples.

If each element of a vector of time series x_i first achieves stationarity after differencing, but a linear combination $\alpha' x_i$ is already stationary, the time series x_i are said to be co-integrated with co-integrating vector α . There may be several such co-integrating vectors so that α becomes a matrix. Interpreting $\alpha' x_i = 0$ as a long run equilibrium, co-integration implies that deviations from equilibrium are stationary, with finite variance, even though the series themselves are nonstationary and have infinite variance.

The paper presents a representation theorem based on Granger (1983), which connects the moving average, autoregressive, and error correction representations for co-integrated systems. A vector autoregression in differenced variables is incompatible with these representations. Estimation of these models is discussed and a simple but asymptotically efficient two-step estimator is proposed. Testing for co-integration combines the problems of unit root tests and tests with parameters unidentified under the null. Seven statistics are formulated and analyzed. The critical values of these statistics are calculated based on a Monte Carlo simulation. Using these critical values, the power properties of the tests are examined and one test procedure is recommended for application.

In a series of examples it is found that consumption and income are co-integrated, wages and prices are not, short and long interest rates are, and nominal GNP is co-integrated with M2, but not M1, M3, or aggregate liquid assets.

KEYWORDS: Co-integration, vector autoregression, unit roots, error correction, multivariate time series, Dickey-Fuller tests.

1. INTRODUCTION

An individual economic variable, viewed as a time series, can wander extensively and yet some pairs of series may be expected to move so that they do not drift too far apart. Typically economic theory will propose forces which tend to keep such series together. Examples might be short and long term interest rates, capital appropriations and expenditures, household income and expenditures, and prices of the same commodity in different markets or close substitutes in the same market. A similar idea arises from considering equilibrium relationships, where equilibrium is a stationary point characterized by forces which tend to push the economy back toward equilibrium whenever it moves away. If x_t is a vector of economic variables, then they may be said to be in equilibrium when the specific linear constraint

$$\alpha' x_t = 0$$

¹ The authors are indebted to David Hendry and Sam Yoo for many useful conversations and suggestions as well as to Gene Savin, David Dickey, Alok Bhargava, and Marco Lippi. Two referees provided detailed constructive criticism, and thanks go to Yoshi Baba, Sam Yoo, and Alvaro Ecribano who creatively carried out the simulations and examples. Financial support was provided by NSF SES-80-08580 and SES-82-08626. A previous version of this paper was entitled "Dynamic Model Specification with Equilibrium Constraints: Co-integration and Error Correction."

occurs. In most time periods, x_t will not be in equilibrium and the univariate quantity

$$z_t = \alpha' x_t$$

may be called the equilibrium error. If the equilibrium concept is to have any relevance for the specification of econometric models, the economy should appear to prefer a small value of z_t rather than a large value.

In this paper, these ideas are put onto a firm basis and it is shown that a class of models, known as error-correcting, allows long-run components of variables to obey equilibrium constraints while short-run components have a flexible dynamic specification. A condition for this to be true, called co-integration, was introduced by Granger (1981) and Granger and Weiss (1983) and is precisely defined in the next section. Section 3 discusses several representations of co-integrated systems, Section 4 develops estimation procedures, and Section 5 develops tests. Several applications are presented in Section 6 and conclusions are offered in Section 7. A particularly simple example of this class of models is shown in Section 4, and it might be useful to examine it for motivating the analysis of such systems.

2. INTEGRATION, CO-INTEGRATION, AND ERROR CORRECTION

It is well known from Wold's theorem that a single stationary time series with no deterministic components has an infinite moving average representation which is generally approximated by a finite autoregressive moving average process. See, for example, Box and Jenkins (1970) or Granger and Newbold (1977). Commonly however, economic series must be differenced before the assumption of stationarity can be presumed to hold. This motivates the following familiar definition of integration:

DEFINITION: A series with no deterministic component which has a stationary, invertible, ARMA representation after differencing d times, is said to be integrated of order d, denoted $x_i \sim I(d)$.

For ease of exposition, only the values d = 0 and d = 1 will be considered in much of the paper, but many of the results can be generalized to other cases including the fractional difference model. Thus, for d = 0 x_t will be stationary and for d = 1 the change is stationary.

There are substantial differences in appearance between a series that is I(0) and another that is I(1). For more discussion see, for example, Feller (1968) or Granger and Newbold (1977).

(a) If $x_t \sim I(0)$ with zero mean then (i) the variance of x_t is finite; (ii) an innovation has only a temporary effect on the value of x_t ; (iii) the spectrum of x_t , $f(\omega)$, has the property $0 < f(0) < \infty$; (iv) the expected length of times between crossings of x = 0 is finite; (v) the autocorrelations, ρ_k , decrease steadily in magnitude for large enough k, so that their sum is finite.

(b) If $x_t \sim I(1)$ with $x_0 = 0$, then (i) variance x_t goes to infinity as t goes to infinity; (ii) an innovation has a permanent effect on the value of x_t , as x_t is the sum of all previous changes; (iii) the spectrum of x_t has the approximate shape $f(\omega) \sim A\omega^{-2d}$ for small ω so that in particular $f(0) = \infty$; (iv) the expected time between crossings of x = 0 is infinite; (v) the theoretical autocorrelations, $\rho_k \to 1$ for all k as $t \to \infty$.

The theoretical infinite variance for an I(1) series comes completely from the contribution of the low frequencies, or long run part of the series. Thus an I(1) series is rather smooth, having dominant long swings, compared to an I(0) series. Because of the relative sizes of the variances, it is always true that the sum of an I(0) and an I(1) will be I(1). Further, if a and b are constants, $b \neq 0$, and if $x_t \sim I(d)$, then $a + bx_t$ is also I(d).

If x_t and y_t are both I(d), then it is generally true that the linear combination

$$z_t = x_t - ay_t$$

will also be I(d). However, it is possible that $z_t \sim I(d-b)$, b>0. When this occurs, a very special constraint operates on the long-run components of the series. Consider the case d=b=1, so that x_t , y_t are both I(1) with dominant long run components, but z_t is I(0) without especially strong low frequencies. The constant a is therefore such that the bulk of the long run components of x_t and y_t cancel out. For a=1, the vague idea that x_t and y_t cannot drift too far apart has been translated into the more precise statement that "their difference will be I(0)." The use of the constant a merely suggests that some scaling needs to be used before the I(0) difference can be achieved. It should be noted that it will not generally be true that there is an a which makes $z_t \sim I(0)$.

An analogous case, considering a different important frequency, is when x_t and y_t are a pair of series, each having important seasonal component, yet there is an a so that the derived series z_t has no seasonal. Clearly this could occur, but might be considered to be unlikely.

To formalize these ideas, the following definition adapted from Granger (1981) and Granger and Weiss (1983) is introduced:

DEFINITION: The components of the vector x_t are said to be co-integrated of order d, b, denoted $x_t \sim CI(d, b)$, if (i) all components of x_t are I(d); (ii) there exists a vector $\alpha \neq 0$ so that $z_t = \alpha' x_t \sim I(d-b)$, b > 0. The vector α is called the co-integrating vector.

Continuing to concentrate on the d=1, b=1 case, co-integration would mean that if the components of x_t were all I(1), then the equilibrium error would be I(0), and z_t will rarely drift far from zero if it has zero mean and z_t will often cross the zero line. Putting this another way, it means that equilibrium will occasionally occur, at least to a close approximation, whereas if x_t was not co-integrated, then z_t can wander widely and zero-crossings would be very rare, suggesting that in this case the equilibrium concept has no practical implications.

The reduction in the order of integration implies a special kind of relationship with interpretable and testable consequences. If however all the elements of x_i are already stationary so that they are I(0), then the equilibrium error z_i has no distinctive property if it is I(0). It could be that $z_i \sim I(-1)$, so that its spectrum is zero at zero frequency, but if any of the variables have measurement error, this property in general cannot be observed and so this case is of little realistic interest. When interpreting the co-integration concept it might be noted that in the N=2, d=b=1 case, Granger and Weiss (1983) show that a necessary and sufficient condition for co-integration is that the coherence between the two series is one at zero frequency.

If x_t has N components, then there may be more than one cointegrating vector α . It is clearly possible for several equilibrium relations to govern the joint behavior of the variables. In what follows, it will be assumed that there are exactly r linearly independent co-integrating vectors, with $r \le N-1$, which are gathered together into the $N \times r$ array α . By construction the rank of α will be r which will be called the "co-integrating rank" of x_t .

The close relationship between co-integration and error correcting models will be developed in the balance of the paper. Error correction mechanisms have been used widely in economics. Early versions are Sargan (1964) and Phillips (1957). The idea is simply that a proportion of the disequilibrium from one period is corrected in the next period. For example, the change in price in one period may depend upon the degree of excess demand in the previous period. Such schemes can be derived as optimal behavior with some types of adjustment costs or incomplete information. Recently, these models have seen great interest following the work of Davidson, Hendry, Srba, and Yeo (1978) (DHSY), Hendry and von Ungern Sternberg (1980), Currie (1981), Dawson (1981), and Salmon (1982) among others.

For a two variable system a typical error correction model would relate the change in one variable to past equilibrium errors, as well as to past changes in both variables. For a multivariate system we can define a general error correction representation in terms of B, the backshift operator, as follows.

DEFINITION: A vector time series x_t has an error correction representation if it can be expressed as:

$$A(B)(1-B)x_t = -\gamma z_{t-1} + u_t$$

where u_t is a stationary multivariate disturbance, with A(0) = I, A(1) has all elements finite, $z_{\tau} = \alpha' x_{\tau}$, and $\gamma \neq 0$.

In this representation, only the disequilibrium in the previous period is an explanatory variable. However, by rearranging terms, any set of lags of the z can be written in this form, therefore it permits any type of gradual adjustment toward a new equilibrium. A notable difference between this definition and most of the applications which have occurred is that this is a multivariate definition which does not rest on exogeneity of a subset of the variables. The notion that one

variable may be weakly exogenous in the sense of Engle, Hendry, and Richard (1983) may be investigated in such a system as briefly discussed below. A second notable difference is that α is taken to be an unknown parameter vector rather than a set of constants given by economic theory.

3. PROPERTIES OF CO-INTEGRATED VARIABLES AND THEIR REPRESENTATIONS

Suppose that each component of x_i is I(1) so that the change in each component is a zero mean purely nondeterministic stationary stochastic process. Any known deterministic components can be subtracted before the analysis is begun. It follows that there will always exist a multivariate Wold representation:

$$(3.1) (1-B)x_t = C(B)\varepsilon_t,$$

taken to mean that both sides will have the same spectral matrix. Further, C(B) will be uniquely defined by the conditions that the function $\det [C(z)]$, $z = e^{i\omega}$, have all zeroes on or outside the unit circle, and that $C(0) = I_N$, the $N \times N$ identity matrix (see Hannan (1970, p. 66)). In this representation the ε_t are zero mean white noise vectors with

$$E[\varepsilon_t \varepsilon_s'] = 0, \quad t \neq s,$$

= G, \quad t = s,

so that only contemporaneous correlations can occur.

The moving average polynomial C(B) can always be expressed as

(3.2)
$$C(B) = C(1) + (1-B)C^*(B)$$

by simply rearranging the terms. If C(B) is of finite order, then $C^*(B)$ will be of finite order. If $C^*(1)$ is identically zero, then a similar expression involving $(1-B)^2$ can be defined.

The relationship between error correction models and co-integration was first pointed out in Granger (1981). A theorem showing precisely that co-integrated series can be represented by error correction models was originally stated and proved in Granger (1983). The following version is therefore called the Granger Representation Theorem. Analysis of related but more complex cases is covered by Johansen (1985) and Yoo (1985).

Granger Representation Theorem: If the $N \times 1$ vector x_t given in (3.1) is co-integrated with d = 1, b = 1 and with co-integrating rank r, then:

- (1) C(1) is of rank N-r.
- (2) There exists a vector ARMA representation

$$(3.3) A(B)x_t = d(B)\varepsilon_t$$

with the properties that A(1) has rank r and d(B) is a scalar lag polynomial with d(1) finite, and $A(0) = I_N$. When d(B) = 1, this is a vector autoregression.

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(3) There exist $N \times r$ matrices, α , γ , of rank r such that

$$\alpha'C(1) = 0$$
,
 $C(1)\gamma = 0$,
 $A(1) = \gamma\alpha'$.

(4) There exists an error correction representation with $z_t = \alpha' x_t$, an $r \times 1$ vector of stationary random variables:

(3.4)
$$A^*(B)(1-B)x_t = -\gamma z_{t-1} + d(B)\varepsilon_t$$

with $A^*(0) = I_N$.

(5) The vector z_t is given by

$$(3.5) z_t = K(B)\varepsilon_t,$$

$$(3.6) (1-B)z_t = -\alpha'\gamma z_{t-1} + J(B)\varepsilon_t,$$

where K(B) is an $r \times N$ matrix of lag polynomials given by $\alpha' C^*(B)$ with all elements of K(1) finite with rank r, and det $(\alpha' \gamma) > 0$.

(6) If a finite vector autoregressive representation is possible, it will have the form given by (3.3) and (3.4) above with d(B) = 1 and both A(B) and $A^*(B)$ as matrices of finite polynomials.

In order to prove the Theorem the following lemma on determinants and adjoints of singular matrix polynomials is needed.

LEMMA 1: If $G(\lambda)$ is a finite valued $N \times N$ matrix polynomial on $\lambda \in [0, 1]$, with rank G(0) = N - r for $0 \le r \le N$, and if $G^*(0) \ne 0$ in

$$G(\lambda) = G(0) + \lambda G^*(\lambda),$$

then

(i)
$$det(G(\lambda)) = \lambda^r g(\lambda) I_N$$
 with $g(0)$ finite,

(ii)
$$Adj(G(\lambda)) = \lambda^{r-1}H(\lambda),$$

where I_N is the $N \times N$ identity matrix, $1 \le rank \ (H(0)) \le r$, and H(0) is finite.

PROOF: The determinant of G can be expressed in a power series in λ as

$$\det (G(\lambda)) = \sum_{i=0}^{\infty} \delta_i \lambda^i.$$

Each δ_i is a sum of a finite number of products of elements of $G(\lambda)$ and therefore is itself finite valued. Each has some terms from G(0) and some from $\lambda G^*(\lambda)$. Any product with more than N-r terms from G(0) will be zero because this will be the determinant of a submatrix of larger order than the rank of G(0). The only possible non-zero terms will have r or more terms from $\lambda G^*(\lambda)$ and

therefore will be associated with powers of λ of r or more. The first possible nonzero δ_i is δ_r .

Defining

$$g(\lambda) = \sum_{i=r}^{\infty} \delta_i \lambda^{i-r}$$

establishes the first part of the lemma since δ_r must be finite.

To establish the second statement, express the adjoint matrix of G in a power series in λ :

Adj
$$G(\lambda) = \sum_{i=0}^{\infty} \lambda^{i} H_{i}$$
,

Since the adjoint is a matrix composed of elements which are determinants of order N-1, the above argument establishes that the first r-1 terms must be identically zero. Thus

Adj
$$G(\lambda) = \lambda^{r-1} \sum_{r=1}^{\infty} \lambda^{i-r+1} H_i$$

= $\lambda^{r-1} H(\lambda)$.

Because the elements of H_{r-1} are products of finitely many finite numbers, H(0) must be finite.

The product of a matrix and its adjoint will always give the determinant so:

$$\lambda' g(\lambda) I_N = (G(0) + \lambda G^*(\lambda)) H(\lambda)$$
$$= G(0) H(\lambda) \lambda^{r-1} + h(\lambda) G^*(\lambda) \lambda'.$$

Equating powers of λ we get

$$G(0)H(0) = 0.$$

Thus the rank of H(0) must be less than or equal to r as it lies entirely in the column null space of the rank N-r matrix G(0). If r=1, the first term in the expression for the adjoint will simply be the adjoint of G(0) which will have rank 1 since G(0) has rank N-1.

Q.E.D.

PROOF OF GRANGER REPRESENTATION THEOREM: The conditions of the Theorem suppose the existence of a Wold representation as in (3.1) for an N vector of random variables x_i , which are co-integrated. Suppose the co-integrating vector is α so that

$$z_t = \alpha' x_t$$

is an r-dimensional stationary purely nondeterministic time series with invertible moving average representation. Multiplying α times the moving average representation in (3.1) gives

$$(1-B)z_t = (\alpha'C(1) + (1-B)\alpha'C^*(B))\varepsilon_t.$$

For z_r to be I(0), $\alpha'C(1)$ must equal 0. Any vector with this property will be a co-integrating vector; therefore C(1) must have rank N-r with a null space containing all co-integrating vectors. It also follows that $\alpha'C^*(B)$ must be an invertible moving average representation and in particular $\alpha'C^*(1) \neq 0$. Otherwise the co-integration would be with b=2 or higher.

Statement (2) is established using Lemma 1, letting $\lambda = (1 - B)$, $G(\lambda) = C(B)$, $H(\lambda) = A(B)$, and $g(\lambda) = d(B)$. Since C(B) has full rank and equals I_N at B = 0, its inverse is A(0) which is also I_N .

Statement (3) follows from recognition that A(1) has rank between 1 and r and lies in the null space of C(1). Since α spans this null space, A(1) can be written as linear combinations of the co-integrating vectors

$$A(1) = \gamma \alpha'$$
.

Statement (4) follows by manipulation of the autoregressive structure. Rearranging terms in (3.3) gives:

$$[\tilde{A}(B)+A(1)](1-B)x_{t}=-A(1)x_{t-1}+d(B)\varepsilon_{t},$$

$$A^{*}(B)(1-B)x_{t}=-\gamma z_{t-1}+d(B)\varepsilon_{t},$$

$$A^*(0) = A(0) = I_N$$
.

The fifth condition follows from direct substitution in the Wold representation. The definition of co-integration implies that this moving average be stationary and invertible. Rewriting the error correction representation with $A^*(B) = I + A^{**}(B)$ where $A^{**}(0) = 0$, and premultiplying by α' gives:

$$(1-B)z_{t} = -\alpha'\gamma z_{t-1} + [\alpha'd(B) + \alpha'A^{**}(B)C(B)]\varepsilon_{t}$$
$$= -\alpha'\gamma z_{t-1} + J(B)\varepsilon_{t}.$$

For this to be equivalent to the stationary moving average representation the autoregression must be invertible. This requires that $\det (\alpha' \gamma) > 0$. If the determinant were zero then there would be at least one unit root, and if the determinant were negative, then for some value of ω between zero and one,

$$\det (I_r - (I_r - \alpha' \gamma) \omega) = 0,$$

implying a root inside the unit circle.

Condition six follows by repeating the previous steps, setting d(B) = 1.

Q.E.D.

Stronger results can be obtained by further restrictions on the multiplicity of roots in the moving average representations. For example, Yoo (1985), using Smith Macmillan forms, finds conditions which establish that $d(1) \neq 0$, that $A^*(1)$ is of full rank, and that facilitate the transformation from error correction models to co-integrated models. However, the results given above are sufficient for the estimation and testing problems addressed in this paper.

The autoregressive and error correction representations given by (3.3) and (3.4) are closely related to the vector autoregressive models so commonly used in econometrics, particularly in the case when d(B) can reasonably be taken to be 1. However, each differs in an important fashion from typical VAR applications. In the autoregressive representation

$$A(B)x_{t} = \varepsilon_{t}$$

the co-integration of the variables x_t generates a restriction which makes A(1) singular. For t = 1, this matrix will only have rank 1. The analysis of such systems from an innovation accounting point of view is treacherous as some numerical approaches to calculating the moving average representation are highly unstable.

The error correction representation

$$A^*(B)(1-B)x_t = -\gamma \alpha' x_{t-1} + \varepsilon_t$$

looks more like a standard vector autoregression in the differences of the data. Here the co-integration is implied by the presence of the levels of the variables so a pure VAR in differences will be misspecified if the variables are co-integrated.

Thus vector autoregressions estimated with co-integrated data will be misspecified if the data are differenced, and will have omitted important constraints if the data are used in levels. Of course, these constraints will be satisfied asymptotically but efficiency gains and improved multistep forecasts may be achieved by imposing them.

As $x_t \sim I(1)$, $z_t \sim I(0)$, it should be noted that all terms in the error correction models are I(0). The converse also holds; if $x_t \sim I(1)$ are generated by an error correction model, then x_t is necessarily co-integrated. It may also be noted that if $x_t \sim I(0)$, the generation process can always be written in the error correction form and so, in this case, the equilibrium concept has no impact.

As mentioned above, typical empirical examples of error correcting behavior are formulated as the response of one variable, the dependent variable, to shocks of another, the independent variable. In this paper all the variables are treated as jointly endogenous; nevertheless the structure of the model may imply various Granger causal orderings and weak and strong exogeneity conditions as in Engle, Hendry, and Richard (1983). For example, a bivariate co-integrated system must have a causal ordering in at least one direction. Because the z's must include both variables and γ cannot be identically zero, they must enter into one or both of the equations. If the error correction term enters into both equations, neither variable can be weakly exogenous for the parameters of the other equation because of the cross equation restriction.

The notion of co-integration can in principle be extended to series with trends or explosive autoregressive roots. In these cases the co-integrating vector would still be required to reduce the series to stationarity. Hence the trends would have to be proportional and any explosive roots would have to be identical for all the series. We do not consider these cases in this paper and recognize that they may complicate the estimation and testing problems.

4. ESTIMATING CO-INTEGRATED SYSTEMS

In defining different forms for co-integrated systems, several estimation procedures have been implicitly discussed. Most convenient is the error correction form (particularly if it can be assumed that there is no moving average term). There remain cross-equation restrictions involving the parameters of the co-integrating vectors; and therefore the maximum likelihood estimator, under Gaussian assumptions, requires an iterative procedure.

In this section, we will propose another estimator which is a two step estimator. In the first step the parameters of the co-integrating vector are estimated and in the second these are used in the error correction form. Both steps require only single equation least squares and it will be shown that the result is consistent for all the parameters. The procedure is far more convenient because the dynamics do not need to be specified until the error correction structure has been estimated. As a byproduct we obtain some test statistics useful for testing for co-integration.

From (3.5) the sample moment matrix of the data can be directly expressed. Let the moment matrix divided by T be denoted by:

$$M_T = 1/T^2 \sum_t x_t x_t'.$$

Recalling that $z_t = \alpha' x_t$, (3.5) implies that

$$\alpha' M_T = \sum_{t} [K(B)\varepsilon_t] x'_t / T^2.$$

Following the argument of Dickey and Fuller (1979) or Stock (1984), it can be shown that for processes satisfying (3.1),

(4.1)
$$\lim_{T \to \infty} E(M_T) = M$$
 a finite nonzero matrix,

and

(4.2)
$$\alpha' M = 0$$
, or $(\operatorname{vec} \alpha)' (I \otimes M) = 0$.

Although the moment matrix of data from a co-integrated process will be nonsingular for any sample, in the limit, it will have rank N-r. This accords well with the common observation that economic time series data are highly collinear so that moment matrices may be nearly singular even when samples are large. Co-integration appears to be a plausible hypothesis from a data analytic point of view.

Equations (4.2) do not uniquely define the co-integrating vectors unless arbitrary normalizations are imposed. Let q and Q be arrays which incorporate these normalizations by reparametrizing α into θ , a $j \times 1$ matrix of unknown parameters which lie in a compact subset of R^j :

(4.3)
$$\operatorname{vec} \alpha = q + Q\theta$$
.

Typically q and Q will be all zeros and ones, thereby defining one coefficient in each column of α to be unity and defining rotations if r > 1. The parameters θ

are said to be "identified" if there is a unique solution to (4.2), (4.3). This solution is given by

$$(4.4) (I \otimes M)Q\theta = -(I \otimes M)q$$

where by the assumption of identification, $(I \otimes M)Q$ has a left inverse even though M does not.

As the moment matrix M_T will have full rank for finite samples, a reasonable approach to estimation is to minimize the sum of squared deviations from equilibrium. In the case of a single co-integrating vector, $\hat{\alpha}$ will minimize $\alpha' M_T \alpha$ subject to any restrictions such as (4.3) and the result will be simply ordinary least squares. For multiple co-integrating vectors, define $\hat{\alpha}$ as the minimizer of the trace $(\alpha' M_T \alpha)$. The estimation problem becomes:

$$\begin{aligned}
& \underset{\alpha s.t.(4.3)}{\operatorname{Min}} \operatorname{tr} \left(\alpha' M_T \alpha \right) = \underset{\alpha s.t.(4.3)}{\operatorname{Min}} \operatorname{vec} \alpha' (I \otimes M_T) \operatorname{vec} \alpha \\
& = \underset{\alpha}{\operatorname{Min}} \left(q + Q \theta \right)' (I \otimes M_T) (q + Q \theta),
\end{aligned}$$

which implies the solution

$$(4.5) \qquad \hat{\theta} = -(Q'(I \otimes M_T)Q)^{-1}(Q'(I \otimes M_T)q), \quad \text{vec } \hat{\alpha} = q + Q\hat{\theta}.$$

This approach to estimation should provide a very good approximation to the true co-integrating vector because it is seeking vectors with minimal residual variance and asymptotically all linear combinations of x will have infinite variance except those which are co-integrating vectors.

When r=1 this estimate is obtained simply by regressing the variable normalized to have a unit coefficient upon the other variables. This regression will be called the "co-integrating regression" as it attempts to fit the long run or equilibrium relationship without worrying about the dynamics. It will be shown to provide an estimate of the elements of the co-integrating vector. Such a regression has been pejoratively called a "spurious" regression by Granger and Newbold (1974) primarily because the standard errors are highly misleading. They were particularly concerned about the non-co-integrated case where there was no relationship but the unit root in the error process led to a low Durbin Watson, a high R^2 , and apparently high significance of the coefficients. Here we only seek coefficient estimates to use in the second stage and for tests of the equilibrium relationship. The distribution of the estimated coefficients is investigated in Stock (1984).

When N=2, there are two possible regressions depending on the normalization chosen. The nonuniqueness of the estimate derives from the well known fact that the least squares fit of a reverse regression will not give the reciprocal of the coefficient in the forward regression. In this case, however, the normalization matters very little. As the moment matrix approaches singularity, the R^2 approaches 1 which is the product of the forward and reverse regression coefficients. This would be exactly true if there were only two data points which,

of course, defines a singular matrix. For variables which are trending together, the correlation approaches one as each variance approaches infinity. The regression line passes nearly through the extreme points almost as if there were just two observations.

Stock (1984) in Theorem 3 proves the following proposition:

PROPOSITION 1: Suppose that x_i satisfies (3.1) with $C^*(B)$ absolutely summable, that the disturbances have finite fourth absolute moments, and that x_i is co-integrated (1, 1) with r co-integrating vectors satisfying (4.3) which identify θ . Then, defining $\hat{\theta}$ by (4.5),

$$(4.6) T^{1-\delta}(\hat{\theta}-\theta) \xrightarrow{p} 0 \text{ for } \delta > 0.$$

The proposition establishes that the estimated parameters converge very rapidly to their probability limits. It also establishes that the estimates are consistent with a finite sample bias of order 1/T. Stock presents some Monte Carlo examples to show that these biases may be important for small samples and gives expressions for calculating the limiting distribution of such estimates.

The two step estimator proposed for this co-integrated system uses the estimate of α from (4.5) as a known parameter in estimating the error correction form of the system of equations. This substantially simplifies the estimation procedure by imposing the cross-equation restrictions and allows specification of the individual equation dynamic patterns separately. Notice that the dynamics did not have to be specified in order to estimate α . Surprisingly, this two-step estimator has excellent properties; as shown in the Theorem below, it is just as efficient as the maximum likelihood estimator based on the known value of α .

THEOREM 2: The two-step estimator of a single equation of an error correction system, obtained by taking $\hat{\alpha}$ from (4.5) as the true value, will have the same limiting distribution as the maximum likelihood estimator using the true value of α . Least squares standard errors will be consistent estimates of the true standard errors.

PROOF: Rewrite the first equation of the error correction system (3.4) as

$$y_{t} = \gamma \hat{z}_{t-1} + W_{t}\beta + \varepsilon_{t} + \gamma (z_{t-1} - \hat{z}_{t-1}),$$

$$z_{t} = X_{t}\alpha,$$

$$\hat{z}_{t} = X_{t}\hat{\alpha},$$

where $X_t = x_t'$, W is an array with selected elements of Δx_{t-i} and y is an element of Δx_t so that all regressors are I(0). Then letting the same variables without subscripts denote data arrays,

$$\sqrt{T}\begin{bmatrix} \gamma & -\gamma \\ \beta & -\beta \end{bmatrix} = [(\hat{z}, W)'(\hat{z}, W)/T]^{-1}[(\hat{z}, W)'(\varepsilon + \gamma)(z - \hat{z})]/\sqrt{T}.$$

This expression simplifies because $\hat{z}'(z-\hat{z})=0$. From Fuller (1976) or Stock (1984), $X'X/T^2$ and X'W/T are both of order 1. Rewriting,

$$W'(z-\hat{z})/\sqrt{T} = [W'X/T][T(\alpha-\hat{\alpha})][1/\sqrt{T}],$$

and therefore the first and second factors to the right of the equal sign are of order 1 and the third goes to zero so that the entire expression vanishes asymptotically. Because the terms in $(z-\hat{z})/\sqrt{T}$ vanish asymptotically, least squares standard errors will be consistent.

Letting $S = \text{plim} [(\hat{z}, W)'(\hat{z}, W)/T],$

$$\sqrt{T} \begin{bmatrix} \gamma & -\gamma \\ \beta & -\beta \end{bmatrix} \stackrel{A}{\to} D(0, \sigma^2 S^{-1})$$

where D represents the limiting distribution. Under additional but standard assumptions, this could be guaranteed to be normal.

To establish that the estimator using the true value of α has the same limiting distribution it is sufficient to show that the probability limit of [(z, W)'(z, W)/T] is also S and that $z'\varepsilon/\sqrt{T}$ has the same limiting distribution as $\hat{z}'\varepsilon/\sqrt{T}$. Examining the off diagonal terms of S first,

$$\hat{z}'W/T - z'W/T = T(\hat{\alpha} - \alpha)'[W'X/T](1/T).$$

The first and second factors are of order 1 and the third is 1/T so the entire expression vanishes asymptotically:

$$(\hat{z}-z)'(\hat{z}-z)/T = z'z/T - \hat{z}'\hat{z}/T$$

= $T(\hat{\alpha}-\alpha)'[X'X/T^2]T(\hat{\alpha}-\alpha)(1/T)$.

Again, the first three factors are of order 1 and the last is 1/T so even though the difference between these covariance matrices is positive definite, it will vanish asymptotically. Finally,

$$(\hat{z}-z)'\varepsilon/\sqrt{T}=T(\hat{\alpha}-\alpha)'[X'\varepsilon/T]1/\sqrt{T},$$

which again vanishes asymptotically.

Under standard conditions the estimator using knowledge of α will be asymptotically normal and therefore the two-step estimator will also be asymptotically normal under these conditions. This completes the proof. Q.E.D.

A simple example will illustrate many of these points and motivate the approach to testing described in the next section. Suppose there are two series, x_{1i} and x_{2i} , which are jointly generated as a function of possibly correlated white noise disturbances ε_{1i} and ε_{2i} according to the following model:

(4.7)
$$x_{1t} + \beta x_{2t} = u_{1t}, \quad u_{1t} = u_{1t-1} + \varepsilon_{1t},$$

$$(4.8) x_{1t} + \alpha x_{2t} = u_{2t}, u_{2t} = \rho u_{2t-1} + \varepsilon_{2t}, |\rho| < 1.$$

Clearly the parameters α and β are unidentified in the usual sense as there are no exogenous variables and the errors are contemporaneously correlated. The

reduced form for this system will make x_{1t} and x_{2t} linear combinations of u_{1t} and u_{2t} and therefore both will be I(1). The second equation describes a particular linear combination of the random variables which is stationary. Hence x_{1t} and x_{2t} are CI(1, 1) and the question is whether it would be possible to detect this and estimate the parameters from a data set.

Surprisingly, this is easy to do. A linear least squares regression of x_{1t} on x_{2t} produces an excellent estimate of α . This is the "co-integrating regression." All linear combinations of x_{1t} and x_{2t} except that defined in equation (4.8) will have infinite variance and, therefore, least squares is easily able to estimate α . The correlation between x_{2t} and u_{2t} which causes the simultaneous equations bias is of a lower order in T than the variance of x_{2t} . In fact the reverse regression of x_{2t} on x_{1t} has exactly the same property and thus gives a consistent estimate of $1/\alpha$. These estimators converge even faster to the true value than standard econometric estimates.

While there are other consistent estimates of α , several apparently obvious choices are not. For example, regression of the first differences of x_1 on the differences of x_2 will not be consistent, and the use of Cochrane Orcutt or other serial correlation correction in the co-integrating regression will produce inconsistent estimates. Once the parameter α has been estimated, the others can be estimated in a variety of ways conditional on the estimate of α .

The model in (4.7) and (4.8) can be expressed in the autoregressive representation (after subtracting the lagged values from both sides and letting $\delta = (1 - \rho)/(\alpha - \beta)$) as:

(4.9)
$$\Delta x_{1t} = \beta \delta x_{1t-1} + \alpha \beta \delta x_{2t-1} + \eta_{1t},$$

(4.10)
$$\Delta x_{2t} = -\delta x_{1t-1} - \alpha \delta x_{2t-1} + \eta_{2t},$$

where the η 's are linear combinations of the ε 's. The error correction representation becomes:

(4.11)
$$\Delta x_{1t} = \beta \delta z_{t-1} + \eta_{1t},$$

$$(4.12) \Delta x_{2t} = -\delta z_{t-1} + \eta_{2t},$$

where $z_t = x_{1t} + \alpha x_{2t}$. There are three unknown parameters but the autoregressive form apparently has four unknown coefficients while the error correction form has two. Once α is known there are no longer constraints in the error correction form which motivates the two-step estimator. Notice that if $\rho \rightarrow 1$, the series are correlated random walks but are no longer co-integrated.

5. TESTING FOR CO-INTEGRATION

It is frequently of interest to test whether a set of variables are co-integrated. This may be desired because of the economic implications such as whether some system is in equilibrium in the long run, or it may be sensible to test such hypotheses before estimating a multivariate dynamic model.

Unfortunately the set-up is nonstandard and cannot simply be viewed as an application of Wald, likelihood ratio, or Lagrange multiplier tests. The testing problem is closely related to tests for unit roots in observed series as initially formulated by Fuller (1976) and Dickey and Fuller (1979, 1981) and more recently by Evans and Savin (1981), Sargan and Bhargava (1983), and Bhargava (1984), and applied by Nelson and Plosser (1983). It also is related to the problem of testing when some parameters are unidentified under the null as discussed by Davies (1977) and Watson and Engle (1982).

To illustrate the problems in testing such an hypothesis, consider the simple model in (4.7) and (4.8). The null hypothesis is taken to be no co-integration or $\rho = 1$. If α were known, then a test for the null hypothesis could be constructed along the lines of Dickey and Fuller taking z_t as the series which has a unit root under the null. The distribution in this case is already nonstandard and was computed through a simulation by Dickey (1976). However, when α is not known, it must be estimated from the data. But if the null hypothesis that $\rho = 1$ is true, α is not identified. Thus only if the series are co-integrated can α be simply estimated by the "co-integrating regression," but a test must be based upon the distribution of a statistic when the null is true. OLS seeks the α which minimizes the residual variance and therefore is most likely to be stationary, so the distribution of the Dickey-Fuller test will reject the null too often if α must be estimated.

In this paper a set of seven test statistics is proposed for testing the null of non-co-integration against the alternative of co-integration. It is maintained that the true system is a bivariate linear vector autoregression with Gaussian errors where each of the series is individually I(1). As the null hypothesis is composite, similar tests will be sought so that the probability of rejection will be constant over the parameter set included in the null. See, for example, Cox and Hinkley (1974, p. 134-136).

Two cases may be distinguished. In the first, the system is known to be of first order and therefore the null is defined by

(5.1)
$$\Delta y_t = \varepsilon_{1t}, \quad \begin{bmatrix} (\varepsilon_{1t}) \\ (\varepsilon_{2t}) \end{bmatrix} \sim N(0, \Omega).$$

This is clearly the model implied by (4.11) and (4.12) when $\rho = 1$ which implies that $\delta = 0$. The composite null thus includes all positive definite covariance matrices Ω . It will be shown below that all the test statistics are similar with respect to the matrix Ω so without loss of generality, we take $\Omega = I$.

In the second case, the system is assumed merely to be a stationary linear system in the changes. Consequently, the null is defined over a full set of stationary autoregressive and moving average coefficients as well as Ω . The "augmented" tests described below are designed to be asymptotically similar for this case just as established by Dickey and Fuller for their univariate tests.

The seven test statistics proposed are all calculable by least squares. The critical values are estimated for each of these statistics by simulation using 10,000 replications. Using these critical values, the powers of the test statistics are

computed by simulations under various alternatives. A brief motivation of each test is useful.

- 1. CRDW. After running the co-integrating regression, the Durbin Watson statistic is tested to see if the residuals appear stationary. If they are nonstationary, the Durbin Watson will approach zero and thus the test rejects non-co-integration (finds co-integration) if DW is too big. This was proposed recently by Bhargava (1984) for the case where the series is observed and the null and alternative are first order models.
- 2. DF. This tests the residuals from the co-integrating regression by running an auxiliary regression as described by Dickey and Fuller and outlined in Table I. It also assumes that the first order model is correct.
- 3. ADF. The augmented Dickey-Fuller test allows for more dynamics in the DF regression and consequently is over-parametrized in the first order case but correctly specified in the higher order cases.
- 4. RVAR. The restricted vector autoregression test is similar to the two step estimator. Conditional on the estimate of the co-integrating vector from the co-integrating regression, the error correction representation is estimated. The test is whether the error correction term is significant. This test requires specification of the full system dynamics. In this case a first order system is assumed. By making the system triangular, the disturbances are uncorrelated, and under normality the t statistics are independent. The test is based on the sum of the squared t statistics.
- 5. ARVAR. The augmented RVAR test is the same as RVAR except that a higher order system is postulated.
- 6. UVAR. The unrestricted VAR test is based on a vector autoregression in the levels which is not restricted to satisfy the co-integration constraints. Under the null, these are not present anyway so the test is simply whether the levels would appear at all, or whether the model can be adequately expressed entirely in changes. Again by triangularizing the coefficient matrix, the F tests from the two regressions can be made independent and the overall test is the sum of the two F's times their degrees of freedom, 2. This assumes a first order system again.
 - 7. AUVAR. This is an augmented or higher order version of the above test.

To establish the similarity of these tests for the first order case for all positive definite symmetric matrices Ω , it is sufficient to show that the residuals from the regression of y on x for general Ω will be a scalar multiple of the residuals for $\Omega = I$. To show this, let ε_{1t} and ε_{2t} be drawn as independent standard normals. Then

(5.2)
$$y_{t} = \sum_{i=1,t} \varepsilon_{1i},$$
$$x_{t} = \sum_{i=1,t} \varepsilon_{2i},$$

and

$$(5.3) u_t = y_t - x_t \sum x_t y_t / \sum x_t^2.$$

To generate y^* and x^* from Ω , let

(5.4)
$$\varepsilon_{2t}^* = c\varepsilon_{2t}, \\ \varepsilon_{1t}^* = a\varepsilon_{2t} + b\varepsilon_{1t},$$

where

$$c = \sqrt{\omega_{xx}}$$
, $a = \omega_{yx}/c$, $b^2 = \omega_{yy} - \omega_{yx}^2/\omega_{xx}$.

Then substituting (5.4) in (5.2)

$$x^* = cx, \quad y^* = ay + bx,$$

$$u^* = y^* - x^* \sum y_t^* x_t^* / \sum x_t^{*2}$$

$$= ay + bx - cx \sum (ay_t + bx_t) cx_t / \sum c^2 x_t^2$$

$$= au,$$

thus showing the exact similarity of the tests. If the same random numbers are used, the same test statistics will be obtained regardless of Ω .

In the more complicated but realistic case that the system is of infinite order but can be approximated by a p order autoregression, the statistics will only be asymptotically similar. Although exact similarity is achieved in the Gaussian fixed regressor model, this is not possible in time series models where one cannot condition on the regressors; similarity results are only asymptotic. Tests 5 and 7 are therefore asymptotically similar if the p order model is true but tests 1, 2, 4, and 6 definitely are not even asymptotically similar as these tests omit the lagged regressors. (This is analogous to the biased standard errors resulting from serially correlated errors.) It is on this basis that we prefer not to suggest the latter tests except in the first order case. Test 3 will also be asymptotically similar under the assumption that u, the residual from the co-integration regression, follows a p order process. This result is proven in Dickey and Fuller (1981, pp. 1065-1066). While the assumption that the system is p order allows the residuals to be of infinite order, there is presumably a finite autoregressive model, possibly of order less than p, which will be a good approximation. One might therefore suggest some experimentation to find the appropriate value of p in either case. An alternative strategy would be to let p be a slowly increasing nonstochastic function of T, which is closely related to the test proposed by Phillips (1985) and Phillips and Durlauf (1985). Only substantial simulation experimentation will determine whether it is preferable to use a data based selection of p for this testing procedure although the evidence presented below shows that estimation of extraneous parameters will decrease the power of the tests.

In Table I, the seven test statistics are formally stated. In Table II, the critical values and powers of the tests are considered when the system is first order. Here the augmented tests would be expected to be less powerful because they estimate parameters which are truly zero under both the null and alternative. The other four tests estimate no extraneous parameters and are correctly specified for this experiment.

From Table II one can perform a 5 per cent test of the hypothesis of non-cointegration with the co-integrating regression Durbin Watson test, by simply

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TABLE I THE TEST STATISTICS: REJECT FOR LARGE VALUES

1. The Co-integrating Regression Durbin Watson: $y_t = \alpha x_t + c + u_t$

$$\xi_1 = DW$$
. The null is $DW = 0$.

2. Dickey Fuller Regression: $\Delta u_t = -\phi u_{t-1} + \varepsilon_t$.

$$\xi_2 = \tau_{\phi}$$
: the t statistic for ϕ .

3. Augmented DF Regression: $\Delta u_t = -\phi u_{t-1} + b_1 \Delta u_{t-1} + \cdots + b_t \Delta u_t - p + \varepsilon_t$.

$$\xi_3 = \tau_{\phi}$$
.

4. Restricted VAR: $\Delta y_t = \beta_1 u_{t-1} + \varepsilon_{1t}$, $\Delta x_t = \beta_2 u_{t-1} + \gamma \Delta y_t + \varepsilon_{2t}$.

$$\xi_4 = \tau_{B1}^2 + \tau_{B2}^2$$
.

5. Augmented Restricted VAR: Same as (4) but with p lags of Δy_t and Δx_t in each equation.

$$\xi_5 = \tau_{B1}^2 + \tau_{B2}^2$$

6. Unrestricted VAR: $\Delta y_t = \beta_1 y_{t-1} + \beta_2 x_{t-1} + c_1 + \varepsilon_{1t}$, $\Delta x_t = \beta_3 y_{t-1} + \beta_4 x_{t-1} + \gamma \Delta y_t + c_2 + \varepsilon_2 + \varepsilon_2 + \varepsilon_3 x_{t-1} + \varepsilon_3$

 $\xi_6 = 2[F_1 + F_2]$ where F_1 is the F statistic for testing β_1 and β_2 both equal to zero in the first equation, and F_2 is the comparable statistic in the second.

7. Augmented Unrestricted VAR: The same as (6) except for p lags of Δx_i and Δy_i in each equation.

$$\gamma_7 = 2[F_1 + F_2].$$

NOTES: y_1 and x_2 are the original data sets and y_2 are the residuals from the co-integrating regression.

checking DW from this regression and, if it exceeds 0.386, rejecting the null and finding co-integration. If the true model is Model II with $\rho=.9$ rather than 1, this will only be detected 20 per cent of the time; however if the true $\rho=.8$ this rises to 66 per cent. Clearly, test 1 is the best in each of the power calculations and should be preferred for this set-up, while test 2 is second in almost every case. Notice also that the augmented tests have practically the same critical values as the basic tests; however, as expected, they have slightly lower power. Therefore, if it is known that the system is first order, the extra lags should not be introduced. Whether a pre-test of the order would be useful remains to be established.

In Table III both the null and alternative hypotheses have fourth order autoregressions. Therefore the basic unaugmented tests now are misspecified while the augmented ones are correctly specified (although some of the intervening lags could be set to zero if this were known). Notice now the drop in the critical values of tests 1, 4, and 6 caused by their nonsimilarity. Using these new critical values, test 3 is the most powerful for the local alternative while at $\rho = .8$, test 1 is the best closely followed by 2 and 3. The misspecified or unaugmented tests 4 and 6 perform very badly in this situation. Even though they were moderately powerful in Table II, the performance here dismisses them from consideration.

Although test 1 has the best performance overall, it is not the recommended choice from this experiment because the critical value is so sensitive to the particular parameters within the null. For most types of economic data the differences are not white noise and, therefore, one could not in practice know

CO-INTEGRATION AND ERROR CORRECTION

TABLE II CRITICAL VALUES AND POWER

I MODEL: Δy , Δx independent standard normal, 100 observations, 10,000 replications,

p = 4.	•			
	Critical	Values		
Statistic	Name	1%	5%	10%
1	CRDW	.511	.386	.322
2	DF	4.07	3.37	3.03
3	ADF	3.77	3.17	2.84
4	RVAR	18.3	13.6	11.0
5	ARVAR	15.8	11.8	9.7
6	UVAR	23.4	18.6	16.0
7	AUVAR	22.6	17.9	15.5
II MODEL: $y_t + 2x_t = $ observation	u_i , $\Delta u_i = (\rho - 1)u_{i-1}$ ons, 1000 replications.		$v_i, \Delta v_i = \eta_i;$	$\rho = .8, .9, 100$
	Rejections pe	er $100: \rho = .$	9	
Statistic	Name	1%	5%	10%
1	CRDW	4.8	19.9	33.6
2	DF	2.2	154	29.0

	7 114 7 7 114	1.0	7.2	11.0
6	UVAR	4.3	13.3	26.1
7	AUVAR	1.6	8.3	16.3
	Rejections per	$r \ 100 : \rho = .3$	8	
 Statistic	Name	1%	5%	10%
1	CRDW	34.0	66.4	82.1
2	DF	20.5	59.2	76.1
3	ADF	7.8	30.9	51.6
4	RVAR	15.8	46.2	67.4
5	ARVAR	4.6	22.4	39.0
6	UVAR	19.0	45.9	63.7

1.5

2.3

1.0

4.8

11.0

11.4

92

18.3

22.7

25.3

17.9

33.4

ADF

RVAR

ARVAR

AUVAR

3

4

what critical value to use. Test 3, the augmented Dickey-Fuller test, has essentially the same critical value for both finite sample experiments, has theoretically the same large sample critical value for both cases, and has nearly as good observed power properties in most comparisons, and is therefore the recommended approach.

Because of its simplicity, the CRDW might be used for a quick approximate result. Fortunately, none of the best procedures require the estimation of the full system, merely the co-integrating regression and then perhaps an auxiliary time series regression.

This analysis leaves many questions unanswered. The critical values have only been constructed for one sample size and only for the bivariate case, although recently, Engle and Yoo (1986) have calculated critical values for more variables

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TABLE III
CRITICAL VALUES AND POWER WITH LAGS

MODEL I: $\Delta y_t = .8\Delta y_{t-4} + \varepsilon_t$, $\Delta x_t = .8\Delta x_{t-4} + \eta_t$; 100 observations, 10,000 replications, p = 4, ε_t , η_t independent standard normal.

	Critical Values				
Statistic	Name	1%	5%	10%	
1	CRDW	.455	.282	.209	
2	DF	3.90	3.05	2.71	
3	ADF	3.73	3.17	2.91	
4	RVAR	37.2	22.4	17.2	
5	ARVAR	16.2	12.3	10.5	
6	UVAR	59.0	40.3	31.4	
7	AUVAR	28.0	22.0	19.2	

MODEL II: $y_t + 2x_t = u_t$, $\Delta u_t = (\rho - 1)u_{t-1} + .8\Delta u_{t-4} + \varepsilon_t$, $y_t + x_t = v_t$, $\Delta v_t = .8\Delta v_{t-4} + \eta_t$; $\rho = .9$, .8. 100 observations, 1000 replications, p = 4.

Rejections per 100: $\rho = .9$					
Statistic	Name	1%	5%	10%	
1	CRDW	15.6	39.9	65.6	
2	DF	9.4	25.5	37.8	
3	ADF	36.0	61.2	72.2	
4	RVAR	.3	4.4	10.9	
5	ARVAR	26.4	48.5	62.8	
6	UVAR	.0	.5	3.5	
7	AUVAR	9.4	26.8	40.3	

Rejections per 100: $\rho = .8$					
Statistic	Name	1%	5%	10%	
1	CRDW	77.5	96.4	98.6	
2	DF	66.8	89.7	96.0	
3	ADF	68.9	90.3	94.4	
4	RVAR	7.0	42.4	62.5	
5	ARVAR	57.2	80.5	89.3	
6	UVAR	2.5	10.8	25.9	
7	AUVAR	32.2	53.0	67.7	

and sample sizes using the same general approach. There is still no optimality theory for such tests and alternative approaches may prove superior. Research on the limiting distribution theory by Phillips (1985) and Phillips and Durlauf (1985) may lead to improvements in test performance.

Nevertheless, it appears that the critical values for ADF given in Table II can be used as a rough guide in applied studies at this point. The next section will provide a variety of illustrations.

6. EXAMPLES

Several empirical examples will be presented to show performance of the tests in practice. The relationship between consumption and income will be studied in some detail as it was analyzed from an error correction point of view in DHSY and a time series viewpoint in Hall (1978) and others. Briefer analyses of wages and prices, short and long term interest rates, and the velocity of money will conclude this section.

DHSY have presented evidence for the error correction model of consumption behavior from both empirical and theoretical points of view. Consumers make plans which may be frustrated; they adjust next period's plans to recoup a portion of the error between income and consumption. Hall finds that U.S. consumption is a random walk and that past values of income have no explanatory power which implies that income and consumption are not co-integrated, at least if income does not depend on the error correction term. Neither of these studies models income itself and it is taken as exogenous in DHSY.

Using U.S. quarterly real per capita consumption on nondurables and real per capita disposable income from 1947-I to 1981-II, it was first checked that the series were I(1). Regressing the change in consumption on its past level and two past changes gave a t statistic of +.77 which is even the wrong sign for consumption to be stationary in the levels. Running the same model with second differences on lagged first differences and two lags of second differences, the t statistic was -5.36 indicating that the first difference is stationary. For income, four past lags were used and the two t statistics were -.01 and -6.27 respectively, again establishing that income is I(1).

The co-integrating regression of consumption (C) on income (Y) and a constant was run. The coefficient of Y was .23 (with a t statistic of 123 and an R^2 of .99). The DW was however .465 indicating that by either table of critical values one rejects the null of "non-co-integration" or accepts co-integration at least at the 5 per cent level. Regressing the change in the residuals on past levels and four lagged changes, the t statistic on the level is 3.1 which is essentially the critical value for the 5 per cent ADF test. Because the lags are not significant, the DF regression was run giving a test statistic of 4.3 which is significant at the 1 per cent level, illustrating that when it is appropriate, it is a more powerful test. In the reverse regression of Y on C, the coefficient is 4.3 which has reciprocal .23, the same as the coefficient in the forward regression. The DW is now .463 and the t statistic from the ADF test is 3.2. Again the first order DF appears appropriate and gives a test statistic of 4.4. Whichever way the regression is run, the data rejects the null of non-co-integration at any level above 5 per cent.

To establish that the joint distribution of C and Y is an error correction system, a series of models was estimated. An unrestricted vector autoregression of the change in consumption on four lags of consumption and income changes plus the lagged levels of consumption and income is given next in Table IV. The lagged levels are of the appropriate signs and sizes for an error correction term and are individually significant or nearly so. Of all the lagged changes, only the first lag of income change is significant. Thus the final model has the error correction term estimated from the co-integrating regression and one lagged change in income. The standard error of this model is even lower than the VAR suggesting the efficiency of the parameter restrictions. The final model passes a

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TABLE IV
REGRESSIONS OF CONSUMPTION AND INCOME

(-2.2) (-2.2) (-2.5) (-2.6) (-2.6) (-7.8)
s (2.5)
s (2.5)
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(2.6)
(2.6)
(2.6)
(2.6)
(2.6)
78
ΙΥ
(-1.1)
(2.4)
()
(2.1)
(2.1)
. /
(4.6)
(4.6) 21
(

NOTES: Data are from 1947-1 to 1981-II. EC are the residuals from the first regression and EY are the residuals from the sixth regression. T ratios are in parentheses.

series of diagnostic tests for serial correlation, lagged dependent variables, non-linearities, ARCH, and omitted variables such as a time trend and other lags.

One might notice that an easy model building strategy in this case would be to estimate the simplest error correction model first and then test for added lags of C and Y, proceeding in a "simple to general" specification search.

The model building process for Y produced a similar model. The same unrestricted VAR was estimated and distilled to a simple model with the error

correction term, first and fourth lagged changes in C and a fourth lagged change in Y. The error correction is not really significant with a t statistic of -1.1 suggesting that income may indeed be weakly exogenous even though the variables are co-integrated. In this case the standard error of the regression is slightly higher in the restricted model but the difference is not significant. The diagnostic tests are again generally good.

Campbell (1985) uses a similar structure to develop a test of the permanent income hypothesis which incorporates "saving for a rainy day" behavior. In this case the error correction term is approximately saving which should be high when income is expected to fall (such as when current income is above permanent income). Using a broader measure of consumption and narrower measure of income he finds the error correction term significant in the income equation.

The second example examines monthly wages and prices in the U.S. The data are logs of the consumer price index and production worker wage in manufacturing over the three decades of 50's, 60's and 70's. Again, the test is run both directions to show that there is little difference in the result. For each of the decades there are 120 observations so the critical values as tabulated should be appropriate.

For the full sample period the Durbin Watson from the co-integrating regression in either direction is a notable .0054. One suspects that this will be insignificantly different from zero even for samples much larger than this. Looking at the augmented Dickey Fuller test statistic, for p on w we find -.6 and for w on p we find +.2. Adding a twelfth lag in the ADF tests improves the fit substantially and raises the test statistics to .88 and 1.50 respectively. In neither case do these approach the critical values of 3.2. The evidence accepts the null of non-co-integration for wages and prices over the thirty year period.

For individual decades none of the ADF tests are significant at even the 10 per cent level. The largest of these six test statistics is for the 50's regressing p on w which reaches 2.4, which is still below the 10 per cent level of 2.8. Thus we find evidence that wages and prices in the U.S. are not co-integrated. Of course, if a third variable such as productivity were available (and were I(1)), the three might be co-integrated.

The next example tests for co-integration between short and long term interest rates. Using monthly yields to maturity of 20 year treasury bonds as the long term rate (R_t) and the one month treasury bill rate r_t as the short rate, co-integration was tested with data from February, 1952 to December, 1982. With the long rate as the dependent variable, the co-integrating regression gave:

$$R_t = 1.93 + .785 r_t + ER_t$$
, $DW = .126$, $R^2 = .866$,

with a t ratio of 46 on the short rate. The DW is not significantly different from zero, at least by Tables II and III; however, the correct critical value depends upon the dynamics of the errors (and of course the sample size is 340—much greater than for the tabulated values). The ADF test with four lags gives:

$$\Delta ER_t = -.06 ER_{t-1}$$
(-3.27)

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+
$$.25 \Delta ER_{t-1}$$
 - $.24 \Delta ER_{t-2}$ + $.24 \Delta ER_{t-3}$ - $.09 \Delta ER_{t-4}$.
(4.55) (-4.15) (-4.15) (-1.48)

When the twelfth lag is added instead of the fourth, the test statistic rises to 3.49. Similar results were found with the reverse regression where the statistics were 3.61 and 3.89 respectively. Each of these test statistics exceeds the 5 per cent critical values from Table III. Thus these interest rates are apparently cointegrated.

This finding is entirely consistent with the efficient market hypothesis. The one-period excess holding yield on long bonds as linearized by Shiller and Campbell (1984) is:

$$EHY = DR_{t-1} - (D-1)R_t - r_t$$

where D is the duration of the bond which is given by

$$D = ((1+c)^{i} - 1)/(c(1+c)^{i-1})$$

with c as the coupon rate and i the number of periods to maturity. The efficient market hypothesis implies that the expectation of the EHY is a constant representing a risk premium if agents are risk averse. Setting $EHY = k + \varepsilon$ and rearranging terms gives the error correction form:

$$\Delta R_t = (D-1)^{-1}(R_{t-1}-r_{t-1})+k'+\varepsilon_t$$

implying that R and r are co-integrated with a unit coefficient and that for long maturities, the coefficients of the error correction term is c, the coupon rate. If the risk premium is varying over time but is I(0) already, then it need not be included in the test of co-integration.

The final example is based upon the quantity theory equation: MV = PY. Empirical implications stem from the assumption that velocity is constant or at least stationary. Under this condition, $\log M$, $\log P$, and $\log Y$ should be co-integrated with known unit parameters. Similarly, nominal money and nominal GNP should be co-integrated. A test of this hypothesis was constructed for four measures of money: M1, M2, and M3, and L, total liquid assets. In each case the sample period was 1959-I through 1981-II, quarterly. The ADF tests statistics were:

where in the first column the log of the monetary aggregate was the dependent variable while in the second, it was $\log GNP$. For only one of the M2 tests is the test statistic significant at the 5 per cent level, and none of the other aggregates are significant even at the 10 per cent level. (In several cases it appears that the DF test could be used and would therefore be more powerful.) Thus the most stable relationship is between M2 and nominal GNP but for the other aggregates, we reject co-integration and the stationarity of velocity.

7. CONCLUSION

If each element of a vector of time series x_t is stationary only after differencing, but a linear combination $\alpha'x_t$ need not be differenced, the time series x_t have been defined to be co-integrated of order (1, 1) with co-integrating vector α . Interpreting $\alpha'x_t = 0$ as a long run equilibrium, co-integration implies that equilibrium holds except for a stationary, finite variance disturbance even though the series themselves are non-stationary and have infinite variance.

The paper presents several representations for co-integrated systems including an autoregressive representation and an error-correction representation. A vector autoregression in differenced variables is incompatible with these representations because it omits the error correction term. The vector autoregression in the levels of the series ignores cross equation constraints and will give a singular autoregressive operator. Consistent and efficient estimation of error correction models is discussed and a two step estimator proposed. To test for co-integration, seven statistics are formulated which are similar under various maintained hypotheses about the generating model. The critical values of these statistics are calculated based on a Monte Carlo simulation. Using these critical values, the power properties of the tests are examined, and one test procedure is recommended for application.

In a series of examples it is found that consumption and income are cointegrated, wages and prices are not, short and long interest rates are, and nominal GNP is not co-integrated with M1, M3, or total liquid assets, although it is possibly with M2.

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Error Correction Mechanisms

Mark Salmon

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MERGING SHORT- AND LONG-RUN FORECASTS An Application of Seasonal Cointegration to Monthly Electricity Sales Forecasting*

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When forecasts of a series Y_i must be made for several horizons, it is a common practice to build different models to forecast different horizons. This paper shows how the information in the several models can be combined in an error-correction framework to yield a single set of forecasts which outperform those from the separate models. The notions of seasonal integration and cointegration are introduced. The methods are applied to forecasting monthly commercial electricity sales with some success. Also reported are results of some simulation experiments designed to evaluate their effectiveness.

1. Introduction

When forecasts of a series of Y_t must be made for several horizons, it is common practice to build different models for different horizons. For ease of exposition just two models will be considered, the short-run (or 'monthly') model and the long-run (or 'annual'). The models are generally used to produce forecasts over different horizons and to help with different types of decisions. There will be only a single data-generating process (d.g.p.) for Y_t , of course, but the two models can be thought of as approximating different parts of this generating process. This paper will discuss the question of how the two models can be merged, or combined, so that a better overall approximation for the d.g.p. can be obtained. This new model could produce superior forecasts at some horizons and also overcomes the practical difficulty of having two different conflicting forecasts at some horizons.

The two models may well have quite different specifications with non-over-lapping sets of explanatory variables. If Y_i is the monthly demand for electricity for some region or utility, the short-run model may concentrate on rapidly changing variables such as those that are strongly seasonal, particularly temperature and other weather variables. The long-run model will be largely based on slowly-moving variables, such as population characteristics,

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appliance stock and efficiencies or a local GNP measure. The variables will be chosen because they are believed to be particularly appropriate and data is available. One model does not ignore the explanatory variables of the other model because they are thought to be of no importance, but because they are thought to be relatively unimportant. To use all of the variables in the short-run model may make it too complicated, and the long-run explanatory variables may not enter significantly when a minimization of a one-month forecast variance is used as a criterion. It will usually also be true that monthly values are not available for some of the slowly changing variables.

In this paper, it will be assumed that the builders of the short-run model are given the task of merging the two models but that they may not have available the past values of the explanatory variables used in the long-run model.

The paper begins by considering the concept of integration and seasonal integration and then the idea of cointegration which proves useful for coordinating the models. A practical example and the results of a simulation study are also presented.

2. The cointegration model

If Y_t is a series such that dth differences $(1-B)^d Y_t$ are stationary, it is called integrated and denoted I(d). A stationary series may be designated I(0). An I(1) series is much smoother or slower-changing than an I(0) series. If a vector of series Y_t , W_t , is I(1) but there exists a linear combination

$$z_t = Y_t - \alpha' W_t, \tag{1}$$

that is I(0), then the series are said to be cointegrated. A typical pair of I(1) series will not have this property. If cointegration occurs, then the data generation process of Y_i can be represented by an 'error-correction' model of the form

$$\Delta Y_t = \delta - \gamma z_{t-1} + \beta' V_t + \varepsilon_t, \tag{2}$$

where V_i are I(0) explanatory variables which could therefore include lags of ΔW or stationary lag polynomials of ΔY . The idea of cointegration, some implications, test procedures and applications can be found in Granger (1986), Engle and Granger (1987) and in the special issue of the Oxford Bulletin of Economics and Statistics, August 1986, Vol. 88, No. 3.

For the problem being considered here, it may be assumed that Y_t contains an I(1) component that is being forecast by the long-run model, so that

$$Y_{t} = C_{0} + C_{1}' W_{t} + \eta_{t}, \tag{3}$$

where W_t is a vector of I(1) components and it is anticipated that $C_1 = \alpha$. The short-run model is assumed to take the form

$$\Delta Y_t = b_0 + b_2' V_t + \varepsilon_t,\tag{4}$$

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where V_t are I(0) variables. As z_t in (2) is based on long-run variables, it is probably not used in the short-run model. Thus, the short-run model is assumed to differ from the error-correction d.g.p. (2) by the omission of the γz_{t-1} term.

In this formulation, there are three forecasting models. The complete 'true' model is given by (2), the long-run forecast will be based on (3) [possibly with η_t being given a simple time-series structure, such as an assumed AR(1) model], and the short-run forecasts are formed from (4).

If data are available frequently enough, say monthly, for all the variables in W_t , and X_t , the complete model (2) can be constructed. One-step forecasts can be found by writing (2) as

$$Y_{t} = \delta - (1 - \gamma)Y_{t-1} + \gamma \alpha' W_{t-1} + \beta' V_{t} + \varepsilon_{t}, \tag{5}$$

and replacing V_t by its forecast. Given forecasts of W_t and V_t , multi-step forecasts of Y_t are found by iterating (5) out to the required horizon. Let $f_{n,h}$ denote the h-step ahead of a forecast made at time n, and suppose we are forecasting just a particular month (say January) in each year in the future. Then the long-run forecasts of the I(0) variables V_t will be just constants (their mean for that month) and so

$$f_{n,h}^{Y} \approx \delta^* + (1 - \gamma) f_{n,h-1}^{Y} + \gamma \alpha' f_{n,h-1}^{W},$$

or

$$f_{n,h+1}^{Y} - f_{n,h}^{Y} \approx \delta^* - \gamma (f_{n,h}^{Y} - \alpha' f_{n,h}^{W}).$$

If the left-hand side is small, or approximately a constant, then the right-hand side shows that

$$f_{n,h}^Y \approx \alpha' f_{n,h}^W + \text{constant},$$
 (6)

as given by the long-run model (3) if $C_1 = \alpha$. Thus, using the complete model one gets short-run forecasts similar to those given by (4) [possibly improved due to the presence of z_{t-1} in (2)], while the long-run forecasts are nearly the same as those from the long-run model (3).

In practice, the complete model is not available, so approximations have to be used. (2) is a convenient form because the long-run specification enters only

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through z_{t-1} and the short-term through V_t . The modeller is assumed to have the full information set except the W_t series. Note that to build (2) one only needs the components of z_{t-1} , which are Y_{t-1} and $\alpha'W_{t-1}$. The latter term is the forecast of Y_{t-1} made from the long-term model. (If W_t is not observed monthly, some interpolation procedure may be required.) If $\hat{f}_{n,h}^{Y}$ is the forecast of Y_{n+h} made at time n from the long-term model, then an estimate of z_t is

$$\hat{z}_t = Y_t - \hat{f}_{t-1,1}^Y$$

An approximation to the full model is found by regressing ΔY_t on a constant, \hat{z}_{t-1} and V_t giving

$$\Delta Y_t = \delta - \gamma \hat{z}_{t-1} + \overline{\beta}' V_t + e_t. \tag{2'}$$

This model is fairly easily achieved once the $\hat{f}_{t-1,1}^{\gamma}$ and V_t terms are obtained, and can be immediately used to form one-step forecasts. It also can be iterated out to form medium and long-term forecasts and the long-term forecasts will be essentially the same as those obtained from (1). Putting t = n + h in (2') and replacing everything by its best forecast, one gets

$$f_{n,h}^{Y} = f_{n,h-1}^{Y} + \delta - \gamma \left(f_{n,h-1}^{Y} - \hat{f}_{n,h-1}^{Y} \right) + \beta' f_{n,h}^{V},$$

assuming the e_t in (2') to be zero-mean white noise. Running these equations for $h = 1, 2, \ldots$ and using $f_{n,0}^Y = Y_n$ etc., one can generate by iteration the forecasts $f_{n,h}^Y$ from the model (2'). Naturally they will not be quite the same as those obtained from the 'true' model (2), but they do represent a reasonable synthesis of the short-run model data and the long-run model forecasts, having the correct long-horizon (large h) properties.

If forecasts are made for every month, the short-run forecast model will provide forecasts of the seasonal component. The long-run model will have nothing to say about this component. Naturally, if just a single month each year is considered, or a annual aggregate, then the seasonal component is of no consequence.

3. Theory of seasonal cointegration

In this section the theory of integration and cointegration at different frequencies, particularly the zero and seasonal frequencies, is introduced. A series may be said to be integrated of order d at frequency θ if the series has a spectrum $f(\omega)$ which takes the form

$$f(\omega) = c(\omega - \theta)^{-2d},$$

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for ω near θ , denoted $x_t \sim I_{\theta}(d)$. For example, a series is integrated just at the zero frequency if $(1-B)^d x_t = C(B)\varepsilon_t + \mu$ and if the spectrum of $C(B)\varepsilon_t$ is bounded away from zero and infinity at all frequencies. If μ is non-zero, the series is $I_0(d)$ with drift. A series may be integrated at any of the seasonal frequencies $\omega_s = 2\pi j/s$, $j = 1, \ldots, s/2$, where data is recorded s times a year. For convenience in this paper it will be assumed that a series is always integrated of the same order at all seasonal frequencies. For example, if x_t is generated by

$$S(B)^{d}x_{t} = C(B)\varepsilon_{t} + \mu,$$

where

$$S(B) = \frac{1 - B^{s}}{1 - B} = (1 + B + B^{2} + \cdots + B^{s-1}),$$

and the spectrum of $C(B)\varepsilon_t$ is bounded as before, then x_t is seasonally integrated of order d, $x_t \sim SI(d)$, with drift if $\mu \neq 0$.

If $x_t \sim_{\theta}(d)$, $d > \frac{1}{2}$ and the series has been generated for an indefinitely long time, it will have an infinite variance. In particular, if d = 1, the variance will be proportional to t, the time since initiation. It is clear from these definitions that a series may be integrated at more than one frequency. For example, if x_t is generated by

$$(1-B^s)x_t=\varepsilon_t,$$

it is $I_0(1)$ and also SI(1).

A vector of series x_t , each component of which is $I_{\theta}(d)$, may be said to be cointegrated at that frequency if there exists a vector α_{θ} such that

$$z_t^{\theta} = \boldsymbol{\alpha}_{\theta}' \boldsymbol{x}_t$$

is integrated of lower order at θ . The case of practical importance is when d=1, so that $z_t^{\theta} \sim I_{\theta}(0)$.

It is convenient to add one further piece of notation. If a series x_t is $I_0(d_0)$ and $SI(d_s)$ it will be denoted $x_t \sim SI(d_0, d_s)$. Thus, if $d_0 = 1$, $d_s = 1$, x_t is integrated of order one at both zero and seasonal frequencies.

These definitions are potentially important for modelling electricity demand as this demand is very likely to be SI(1,1) due to important long-run and seasonal components. Further, if the model has been carefully specified, then the long-run model explanatory variables, $\gamma'W_t$ in (1), should be cointegrated with the seasonally adjusted components of Y_t , and the short-run model explanatory variables, $\beta'V_t$ in (3), should be seasonally cointegrated with differenced Y_t .

Virtually all of the current literature on cointegration fails to consider the effects of seasonal integration. In this literature, it is usual to estimate the cointegrating parameter α in the bivariate case by regressing x_{1t} on x_{2t} , which is called the cointegrating regression. If the resulting residual z_t is I(0), then a superefficient estimate of α results, with a distribution derived by Stock (1987). For series which are seasonally integrated, this result may be lost as shown in the theorem below.

Let $X' = [x_1, ..., x_T]$ be the data for the electricity sales, income and other variables so that X = [Y, W]. The cointegrating regression minimizes the sum of squared residual z'z, from $z = X\alpha$ subject to a normalization restriction such as a unit coefficient on the selected dependent variable.

Theorem. Let X_t be a vector of random variables partitioned so that $X'_t = (x_{1t}, x_{2t}, x_{3t})$, where x_{1t} is SI(1,1), x_{2t} is SI(1,0) and x_{3t} is SI(0,1).

- (a) If X_t is seasonally cointegrated at zero frequency but not seasonal frequencies, then the value of α which minimizes $\alpha' X' X \alpha$ (with $\alpha_3 = 0$) subject to $\alpha' \alpha = 1$ will not generally be consistent, however the α which minimizes $\alpha' \overline{X}' \overline{X} \alpha$ (with $\alpha_3 = 0$) will be consistent where $\overline{x}_t = (1 + B + \cdots + B^{s-1})x_t = S(B)x_t$ and $\overline{X}' = (\overline{x}_1, \dots, \overline{x}_T)$.
- (b) If instead X_t is seasonally cointegrated at seasonal frequencies but not at zero frequency, then the value of α which minimizes $\alpha' X' X \alpha$ (with $\alpha_2 = 0$) will not generally be consistent, however the α which minimizes $\alpha' \tilde{X}' \tilde{X} \alpha$ (with $\alpha_2 = 0$) will be consistent where $\tilde{x}_t = (1 B)x_t$ and $\tilde{X}' = (\tilde{x}_1, \dots, \tilde{x}_T)$.
- (c) If, instead, x_{1t} and x_{2t} are SI(1,1) with drift and SI(1,0) with drift, respectively, but there is an α with $\alpha_3 = 0$ for which $\alpha' X_t \sim I(0)$ without drift, then the value of α which minimizes $\alpha' X' X \alpha$ will be consistent.
- *Proof.* (a) To show that α estimated from the time averaged data will be consistent it is sufficient to show that these data are cointegrated in the usual or Engle/Granger sense. First we show the \bar{x}_t is I(1).

$$(1-B)\bar{x}_t = (1-B)S(B)x_t = C(B)\varepsilon_t,$$

hence \bar{x}_t will be I(1) for x_{1t} which is SI(1,1). For x_{2t} which is SI(1,0), \bar{x}_t is also I(1) because d=1 is the smallest integer satisfying the definition of integration and the zeros in the spectrum at seasonal frequencies are not relevant. To show that $\alpha'\bar{x}_t$ is I(0), one merely notes that, since $\alpha'x_t \sim \text{SI}(0,1)$, by definition $S(B)\alpha'x_t = \alpha'(S(B)x_t) = \alpha'\bar{X}_T \sim \text{I}(0)$. Hence, $\alpha'\bar{x}_t$ is I(0) and \bar{x}_t is CI(1,1).

To show that the cointegrating regression on the untransformed variables x_i , will not necessarily lead to a consistent estimate of α it is sufficient to produce a counterexample. This particular counterexample, however, is revealing of precisely the issue faced in monthly electricity demand modelling. Suppose the

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data are generated by the process

$$y_t = \alpha x_t + u_t,$$

$$(1 + B + \dots + B^{s-1}) u_t = \varepsilon_t,$$

$$x_t = x_{t-1} + \nu_t,$$

where ε and ν are serially independent with arbitrary contemporaneous covariance. Multiplying the first equation by $(1 - B^s)$ gives

$$(1 - Bs) yt = S(B) \nut + (1 - B) \varepsilont,$$

establishing that y is SI(1,1) and not I(1). However, x_t is I(1). The linear combination of $(1, -\alpha)$ times (y, x)' yields a random variable u, which has a finite spectrum at zero frequency although it has spikes or poles at all the seasonals. This vector does not eliminate all seasonal poles so X_t is seasonally cointegrated at zero frequency but not at seasonal frequencies. The regression of y on x can be expressed as

$$\hat{\alpha} = \alpha + (x'x/T^2)^{-1}x'u/T^2.$$

It is well known since Fuller (1976) that $x'x/T^2$ converges in distribution to a random variable rather than a constant. Some tedious algebra shows that in this case $x'u/T^2$ has also a variance which is of O(1) since both x and u have infinite variances, and the ratio will not have a probability limit as required for consistency of the estimator. This counterexample establishes in this particularly simple case that the cointegrating equation on levels is not consistent in the presence of seasonal unit roots unless x is fully cointegrated.

- (b) To establish the similar result for cointegration at seasonal frequencies, exactly the same steps are taken and will not be repeated here. The requirement that $T^{-2}\tilde{X}'\tilde{X} = O_p(1)$ in this case has been established by Chan and Wei (1988).
- (c) To establish the consistency of the cointegrating regression when there are drifts, it must be established that the trends implied by the drifts dominate the seasonality thereby reinstating the consistency of the cointegrating regression. This is essentially shown in Sims, Stock and Watson (1986) and will not be reproduced here.

There are several implications of the theorem for the situation being considered in this paper. It has been assumed that electricity sales are available monthly and that long-run explanatory variables, W_t may not be available monthly, only annually. Since the W_t variables represent income, appliance saturations and so forth which are not seasonal, the use of monthly

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observations on W_t to estimate the cointegrating regression would not result in inconsistent estimates of the long-run parameters α unless there are dominating trends. Only if the sales data were filtered with the S(B) filter, would such a least-squares regression give consistent estimates of α . The use of annual observations on sales and W_t is an example of such filtering and is therefore recommended as an approach to estimating the long-run model without the need to model the seasonality. This is a very simple and old conclusion but is newly justified by the analyses of seasonal cointegration.

4. An empirical example of the error-correction synthesis

Monthly commercial electricity sales for Massachusetts Electric Company, a retail subsidiary of New England Electric Power Service Company was analyzed from January 1975 through May 1985. The same data were analyzed in Pastuszek and Watson (1985) who develop a short-run forecasting model. A stylized version of their model regresses the level of sales on two lagged values, cooling and heating degree days, eleven monthly dummies and a constant. The results are reported in table 1.

From the examination of table 1, the short-run model appears to be well specified. The effects of weather are sensible and the second-order lag in sales should eliminate most serial correlation. However, examination of table 2, which includes a series of diagnostic tests, suggests that there may be problems with the model. There seems to be some first-order serial correlation remaining and some evidence of heteroskedasticity. More serious is the evidence that the variables ECTEST2 and ERROR CORRECTION were inappropriately omitted from the regression. These are the long-run forecast $\hat{f}_{t-1,1}^{\gamma}$ and the error correction terms \hat{z}_{t+1} , respectively, which will be described in more detail below. They indicate that the model seriously omits the long-run or trend component in its modelling. Within the sample, the accuracy of the forecast is highly commendable, however as the model is used to forecast five years into the future, the forecasts exhibit a substantial and uncharacteristic decline. Because the estimated process for sales is stationary, it eventually returns to its unconditional mean.

A possible improvement to this short-run model is to impose the unit root restriction and estimate the model in differences. In this case, the historical trend will be extrapolated, which again may not be desirable.

The long-run model is just a contemporaneous OLS regression that is estimated in two ways for this example. The first uses monthly data, while the second is based on annual data obtained from summing the monthly values. In most applications only the latter will be available. Because there are only ten years of data an extremely simple long-run model is estimated. The basic explanatory variable is the number of Massachusetts Electric commercial customers, labeled MC (or AMC in the annual model). In addition, local

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Table 1
Short-run model of monthly sales.

Variable	Coefficient	Std. error	t-statistic
MCD	0.14	0.03	4.10
MHD	0.03	0.01	2.25
MCD[-1]	-0.07	0.03	-2.05
MHD[-1]	- 0.01	0.01	-1.10
M[-1]	0.64	0.08	7.18
M[-2]	0.28	0.08	3.31
_FEB	- 23.93	6.71	-3.56
_MAR	- 33.67	8.78	-3.83
_APR	-37.18	11.02	-3.37
_ <i>MAY</i>	-25.95	13.56	-1.91
_JUN	-11.38	16.16	-0.70
$_JUL$	− 22.4 6	18.73	-1.19
$_AUG$	-9.84	20.14	-0.48
_SEP	-18.99	19.48	-0.97
_OCT	-23.84	16.50	-1.44
_NOV	-18.68	12.08	-1.54
_DEC	0.88	7.28	0.12
_CONST	25.22	20.87	1.20
	Number of observations	124	
	Mean value of M	289.20	
	Standard deviation of M	28.77	
	Standard error of forecast	9.07	
	R-square (corrected for mean)	0.091	
	F(18,106)	62.81	
	Adjusted R-square	0.89	
	Durbin-Watson statistic	2.29	
	AIC error statistic	9.70	
	Schwartz error statistic	11.90	

Table 2
Diagnostic test statistics.

ECTEST2	Chi-square(1)	30.65	p = 1.000
ERROR CORRECTION	Chi-square(1)	27.51	p = 1.000
AUTO[-1] serial correlation	Chi-square(1)	14.67	p = 1.000
NONLINEARITY in x test	Chi-square(6)	2.14	p = 0.093
HETEROSCEDASTICITY TIME	Chi-square(1)	0.03	p = 0.144
HETEROSCEDASTICITY with X	Chi-square(18)	31.51	p = 0.975
HETEROSCEDASTICITY YFIT	Chi-square(1)	5.27	p = 0.978
ARCH[-1] process test	Chi-square(1)	21.21	p = 1.000
ARCH[-12] process test	Chi-square(1)	0.00	p = 0.027
CHOW test	F(18, 88)	1.27	p = 0.804

Table 3	
Long-run model estimated from monthly day	ta.

Variable	Coefficient	Std. errror	t-statistic
\overline{MU}	- 2.614946	1.494347	-1.74
MC	0.006263	0.000915	6.84
_CONST	-105.922279	66.974351	-1.58
	Number of observations	112	
	Mean value of M	293.00	
	(Standard deviation)	(27.03)	
	Standard error of forecast	19.88	
	Adjusted R-square	0.45	
	Durbin-Watson statistic	0.95	

Table 4
Long-run model from annual data.

Variable	Coefficient	Std. error	t-statistic
\overline{AU}	- 40,963840	8.001853	- 5.11
AC	0.071864	0.006373	11.27
_CONST	- 991.846822	460.045640	~ 2.15
	Number of observations	10	
	Mean value of AM	3435.16	
	(Standard deviation)	(243.86)	
	Standard error of forecast	34.84	
	Adjusted R-square	0.097	
	Durbin-Watson Statistic	2.73	

economic conditions may determine the level of intensity of use by these customers so the local unemployment, MU (or AMU in the annual model), is also used. Some experiments with relative prices suggest that price would not help the model. The results are presented in tables 3 and 4. Because these regressions are cointegrating regressions, the disturbances are assumed merely to be stationary, not white noise. Thus the t-statistics will not be reliable guides to the inclusion of variables in these regressions. One test for the cointegration hypothesis, which is only appropriate in the non-seasonal case, is based on the Durbin-Watson statistic for the cointegrating regression. The value of 0.95 from the monthly regression would easily confirm the conjecture that these three variables are cointegrated if there were no seasonality. The precise nature of such tests in the presence of seasonality is a topic for further research.

The forecasts from these two models were constructed for five years or until 1990. In the first case, the forecasts were monthly, while in the second the

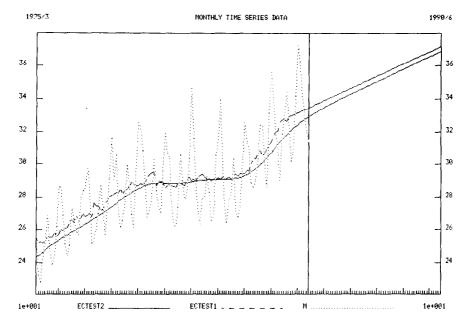


Fig. 1

forecasts were annual but were interpolated to monthly values using spline interpolation. The series have no seasonality and are best interpreted as 'weather and seasonally adjusted sales' forecasts. Since these series are to be used in error-correction models, they are called *ECTEST1* and *ECTEST2*, respectively. In each case the out of sample forecasts were based upon simple Box-Jenkins models of *MC* and *MU*. Thus the historical trends in these series were projected to continue and, consequently, the prediction is that sales will continue to increase. In actual forecasting, however, electric utilities often have more information on the likely path of the independent variables. This leads to the construction of one or more forecast scenarios. In *ECTEST3*, it is assumed that unemployment and customers remain constant over the next five years. This series is identical with *ECTEST2* except during the post-sample period. *ECTEST1* and *ECTEST2* scenarios are plotted with the historical data on *M* in fig. 1.

Error-correction models were then estimated using each of the long-run forecasts in the error-correction term. That is, a regressor M[-1] - ECTESTI[-1] was introduced into the short-run model and is anticipated to have a negative coefficient. When M is above its long-run forecast, there is downward pressure on M next period. The short-run model is built on the first difference of sales and has as explanatory variables, lagged changes in sales

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Table 5
Error-correction model using monthly long-run model.

Variable	Coefficient	Std. error	T-statistic
MCD	0.128022	0.014416	8.88
MHD	0.055242	0.004204	13.14
MCD[-1]	0.035419	0.020368	1.73
MHD[-1]	0.000271	0.006114	0.04
M[-1]-M[-2]	0.226384	0.061441	3.68
M[-1] - ECTESTI[-1]	-1.130600	0.098280	-11.50
CONST	-41.220136	4.422205	-9.32
Number of o	bservations	124	
Mean value	of _DM	0.35	
(Standard	deviation)	(18.80)	
	or of forecast	7.83	
Adjusted R-	square	0.82	
Durbin-Wa		2.15	

Table 6
Error-correction model using annual long-run forecast.

Variable	Coefficient	Std. error	t-statistic
MCD	0.141101	0.015230	9.26
MHD	0.055315	0.004530	12.21
MCD[-1]	0.014629	0.021370	0.68
MHD[-1]	-0.004948	0.006501	-0.76
M[-1] - M[-2]	0.190117	0.065617	2.89
M[-1] - ECTEST2[-1]	-1.010415	0.101993	-9.90
CONST	-33.543761	4.400422	-7.62
Number of observations		124	
Mean value of _DM		0.35	
(Standard deviation)		(18.80)	
Standard error of forecast		8.43	
Adjusted R-square		0.79	
Durbin-Watson statistic		1.91	

and current and lagged weather variables. The lagged weather is anticipated to be important through billing cycle effects. The only trend variable is the long-run forecast which is constrained in the error-correction term to have the same coefficient as the lagged level of M. If there were no error-correction term, then the trend would be modelled solely by the intercept in the first difference model as illustrated by the short-run model above. The results are presented in tables 5 and 6 for the two long-run forecasts.

The estimates for both models are highly encouraging. In each case the error-correction term is highly significant and of the correct sign. The weather

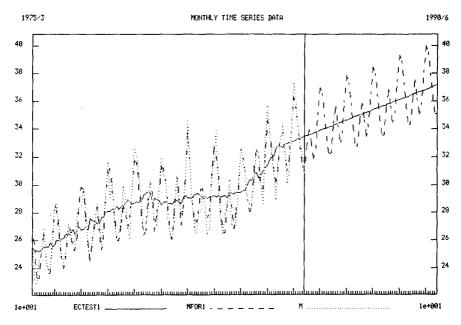


Fig. 2

variables are significant although the lags are probably not necessary. The diagnostic tests for the monthly model found that the model is quite clean against a wide range of possible misspecifications. There is some evidence that seasonal dummy variables would improve the fit, but there is no test which rejects at the 99% level, which is unusual when so many tests are carried out. There is somewhat more evidence against the *ECTEST2* version of the error-correction model.

These two models were then used to forecast Massachusetts commercial sales for the next five years. The forecasts for ECTEST2 are presented in fig. 2. Superimposed in this figure are the original series M through 1985, the long-run forecast within sample and out of sample, and the merged forecast labeled MFOR. The forecasts using ECTEST1 are similar but lower, and those from ECTEST3 are that in the post-sample period. These forecasts are seen to accomplish the purpose of providing a short-run forecast which accurately predicts the seasonality and short-run movements in sales but which is consistent with the long-run forecast over the longer period.

5. A simulation study

To evaluate the effectiveness of the various techniques introduced above, a simulation study was conducted. Data were generated using a model which

has properties similar to the electricity data and used to build long-run, short-run and merged models. From each of these data sets and models, multi-step forecasts were constructed and the results compared for accuracy on post-sample data. In each case, the independent variables were forecast assuming that the form of the equation was known but not its coefficients. Therefore, all forecasts are interpreted as unconditional forecasts. Surely forecasts conditional on the long-run variables would dramatically favor the long-run and merged models. Thirty-eight years of data were generated for each replication. The first 28 were used to fit the models, and then the final 10 years of 120 months were forecast conditional only on the first 28-year data set. Mean squared forecast errors of each forecast horizon were computed across 500 replications. Thus the forecast errors are not constructed by rolling the sample period forward but correspond to a fixed time period.

The data for electricity sales, y_i , was generated from

$$y_t = m_1 + 0.6y_{t-1} + w_t + v_t + \varepsilon_{1t}, \tag{7}$$

where w, is the long-run component generated by

$$w_{t} = m_{2} + 0.5w_{t-12} + 0.5w_{t-24} + \varepsilon_{2t}, \tag{8}$$

and the seasonal or temperature-based component was generated by

$$v_t = v_{t-12} + \varepsilon_{3t} - \varepsilon_{3t-1}. \tag{9}$$

These parameter values imply that w_t is SI(1,1) if $m_2 = 0$ and SI(1,1) with drift otherwise, while v_t is SI(0,1). This is easily seen by rewriting (8) and (9) as

$$(1 - B^{12})(1 + 0.5B^{12})w_t = m_2 + \varepsilon_{2t},$$

 $S(B)v_t = \varepsilon_{3t}.$

From (7) it is immediately deduced that y is SI(1,1) if $m_2=0$ and SI(1,1) with drift otherwise, and that y and w are seasonally cointegrated at zero frequency but not at seasonal frequencies. The relationship at zero frequency says that

$$v_{r} = 2.5w_{r} + u_{r}$$

where u_t still has seasonal unit roots as well as stationary components. It also

appears that y and v are seasonally cointegrated at seasonal frequencies; however, a slightly more general definition of seasonal cointegration is required here to incorporate the dynamic relationship for these variables. As this is not needed for our analysis we leave this point.

To mimic actual data, the initial values of the seasonal were taken to be 90, 80, 60, 40, 20, 50, 70, 80, 60, 30, 60, 80, so that the series peak in January and August. All ε_t are assumed to be N(0, 1) white noise. In the simulation first reported $m_1 = 1$ and $m_2 = 12$ so that annualized w_t is essentially a linear trend. In the second simulation, $m_2 = 1$ so that the trend is a minor component of the series.

The short-run model relates the change in y_t to the changes in the seasonal variables and to lagged changes in y_t . The equation estimated is

$$\Delta y_t = \delta_0 + \delta_1 \Delta y_{t-1} + \delta_2 \Delta v_t + e_1, \tag{10}$$

This equation can be derived by differencing (7) and then treating $\Delta(w_t + \varepsilon_{1t})$ as e_{1t} . One might expect that this error would be serially correlated and therefore higher-order lags were introduced into (10), but there was not very much difference in the performance of the equation. The lagged dependent variable presumably captured much of this effect.

The long-run model was estimated using a cointegrating regression under one of three data assumptions. Letting τ index annual data,

$$y_{\tau} = \alpha_0 + \alpha w_{\tau} + e_{2\tau}. \tag{11}$$

The three assumptions are:

- (i) All data are used so that the model is estimated as though the long-run explanatory variable w_t is available monthly and the subscript τ in (11) is implicitly replaced with t.
- (ii) Every twelfth data point is used so that the long-run explanatory variable is treated as a stock and point sampled. The December observation is chosen.
- (iii) Twelve-month averages are used for the data in (11) under the assumption that w_t is a flow variable. The Theorem in section 3 suggests that this version will be consistent, whereas version (i) will not when there is no drift. However, version (i) uses twelve times as many observations and may have a smaller variance, and when there is a drift in w_t , the Theorem implies that version (i) will be consistent as well. In practice usually only one of these series on w would be available, so there is no choice.

Three error-correction models were estimated corresponding to these three long-run models. These take the form

$$\Delta y_t = \beta_0 + \beta_1 v_t + \beta_2 (\hat{y}_t - y_{t-1}) + e_{3t}, \tag{12}$$

where \hat{y}_t is the monthly forecast of y_i made by a long-run model. The monthly version of the long-run model immediately produces monthly forecasts, however the other two versions do not. For these a simple linear interpolation was used. Although this introduced errors into \hat{y} , these appeared to be small as the series was inherently smooth being the long-run prediction.

If the monthly observations on w are available, then the investigator may estimate the true relation (7). As a basis for the comparison we consider estimates of

$$y_{t} = \theta_{0} + \theta_{1} y_{t-1} + \theta_{2} w_{t} + \theta_{3} s_{t} + e_{t}, \tag{13}$$

which should provide the best estimate of both the short- and long-run effects. In practice, we believe that such estimates are not available either because w_t is not measured monthly or because the short- and long-run forecasters cannot agree to use a single model.

The mean square forecast errors for horizons from 1 through 120 months of the various estimators were obtained. The annual model using every twelveth data point is generally inferior to the one using annual averages and so is the associated error-correction model. For this reason, and because the scheme is not even feasible in many cases, we will not mention these models again. Table 7 extracts from the results information on the forecasts of some Januaries from the other models; this controls for the seasonality which makes the interpretation of the long-run models particularly complex.

The results in table 7 are rather clear. Forecasting sales ten years in the future is inherently more uncertain than one year. Forecasting with the correctly specified model is only slightly less accurate than using the true

Table 7
Summary January mean squared forecast errors.

Year		Esti- mated	Long-run model		Error-correction model	
	Actual		Annual	Monthly	Annual	Monthly
1	4.1	4.1	2024	2053	14.9	4.3
2	6.9	7.2	2022	2055	19.7	8.0
3	9.3	9.7	2017	2054	21.7	10.6
5	13.8	15.7	2011	2064	27.4	16.9
10	21.6	28.0	2023	2092	40.3	29.8

parameters. The short-run model is not shown, but was found to perform substantially worse both at short and at long horizons. It was about nine times worse than estimating the true model for one-month forecasts and six times worse for a ten-year horizon. The long-run models, however, are even worse than the short-run model at all horizons. This is primarily because they make no attempt to model the seasonality so that the bulk of the mean squared forecast error is presumably the bias from seasonality. It was found that although the MSFE for the monthly long-run model is 2053 for the one-month forecast, it was only 93 for the three-month forecast.

The most interesting results therefore are the error-correction models. Both the monthly and annual error-correction models perform very well. The monthly is only slightly inferior to estimation of the full correctly specified model, while the annual is not quite as good but still much better than the short- or long-run models themselves. The annual model incurs the added error due to the interpolation of the long-run forecasts and the forecast of the w series using aggregate data and an AR(2) specification. One might expect that this estimation would be considerably less precise than the monthly estimate. Because there is a substantial drift in w_t , part (c) of the Theorem from section 3 suggests on all grounds that the monthly error correction model should be the best.

This simulation experiment bears out the expectations of the theory. It is possible to combine short- and long-run forecasts using an error-correction formulation which conveniently encapsulates the long-run forecast information in a single variable. If there is a choice between estimating the long-run model on monthly data or annual data, one should choose the annual version if seasonality is large component of the monthly variance but use the monthly data if the trend is the dominant component of the monthly variance.

Simulation experiments have also been tried with other parameter values, no drift, more lags in (10) and somewhat different data generation processes for W_t . The results are similar to those reported here. When forecasts are made conditional on W_t , the models using the extra information far outperform (10) as expected. Further detailed results can be obtained from the authors.

6. Conclusions

If there exist two forecasting models, one aiming at the long run and the other at the short run, our suggestion is that the two sets of forecasts be merged by adding an 'error-correction' term into the short-run model. This term consists of the difference between the most recent actual value for the series and the long-run model's forecast of that value. The coefficient on this term will have to be estimated and then the resulting model run forward in time to provide forecasts of a horizon. The experience so far accummulated suggests that this technique will be successful.

R.E. Engle et al., Merging short- and long-run forecasts

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Exhibit I.C2.EGDI.BOMA.12

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BOMA INTERROGATORY #12

INTERROGATORY

Ref: Ibid, p20

Please explain what is meant by balance point heating degree days adjusted by billing cycles (our emphasis).

RESPONSE

Each month Enbridge customer meters are billed on a 20-cycle billing period based on the billing schedules set out for the year. Approximately one hundred thousand customer meters are billed for each cycle until all customers have been billed by the end of each month.

Over that time, daily balance point heating degree day are calculated and aggregated into each billing cycle, which gives the total amount of degree days applicable to each billing cycle for the month. This degree day total for each cycle is proportionally weighted by the number of customers billed for the cycle over the total number of customers billed for the month. The sum of the weighted degree days for all billing cycles in the month would become the heating degree days adjusted by billing cycle.

The following table provides an illustration on how the balance point heating degree days are adjusted by billing cycles for the month of December, 2016 in the Central weather zone.

Witness: M. Suarez

Exhibit I.C2.EGDI.BOMA.12

371.3

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BALANCE POINT METER READING DEGREE DAYS <u>DECEMBER</u>, 2016 - CENTRAL REGION

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
Billing Cycles	Billing Period Start	Billing Period Finish	Number of Degree Days	Number of Customer Billed Per Cycle	Total Unlocks Billed For the Month	Weighted Degree Days for each cycle
						(Col.4 * Col.5/Col.6)
1	11/4/2016	12/3/2016	267.5	80,675	1,620,706	13.3
2	11/5/2016	12/5/2016	286.2	69,961	1,620,706	12.4
3	11/8/2016	12/6/2016	281.6	81,123	1,620,706	14.1
4	11/9/2016	12/7/2016	292.1	81,655	1,620,706	14.7
5	11/10/2016	12/8/2016	299.0	78,003	1,620,706	14.4
6	11/11/2016	12/9/2016	314.8	72,752	1,620,706	14.1
7	11/12/2016	12/10/2016	321.3	78,778	1,620,706	15.6
8	11/15/2016	12/12/2016	329.5	85,535	1,620,706	17.4
9	11/16/2016	12/13/2016	342.7	87,990	1,620,706	18.6
10	11/17/2016	12/14/2016	358.9	93,418	1,620,706	20.7
11	11/18/2016	12/15/2016	377.1	91,935	1,620,706	21.4
12	11/19/2016	12/16/2016	396.5	82,974	1,620,706	20.3
13	11/22/2016	12/19/2016	417.7	79,348	1,620,706	20.5
14	11/23/2016	12/20/2016	420.0	83,231	1,620,706	21.6
15	11/24/2016	12/21/2016	421.7	69,309	1,620,706	18.0
16	11/25/2016	12/22/2016	424.4	83,146	1,620,706	21.8
17	11/26/2016	12/23/2016	427.5	79,402	1,620,706	20.9
18	11/29/2016	12/28/2016	470.0	80,074	1,620,706	23.2
19	11/30/2016	12/29/2016	479.7	78,221	1,620,706	23.2
20	12/1/2016	12/30/2016	490.3	83,176	1,620,706	25.2

1,620,706

December 2016 Meter Reading Balance Point Degree Days

Witness: M. Suarez

Exhibit I.C2.EGDI.BOMA.13

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BOMA INTERROGATORY #13

INTERROGATORY

Ref: Ibid, p21

Please provide copies of the model/equation used to forecast average gas use in 2018 for each of the rates 1 and 6, with explanatory note that illustrates the relative strength of each driver in the equation, eg. heating degree days, vintage (rate 1 only), employment, Ontario grid gross domestic product, vacancy rates (rate 6 only), real energy prices, and a time trend. Please describe and illustrate by, an example, the relative impact of the "time trend" EGD uses.

RESPONSE

The regression equations used by the Company to forecast average use are presented in the pre-filed evidence. Please refer to Exhibit C2, Tab 1, Schedule 3, Table 5 at pages 12 to 13 and Table 8 at pages 16 to 18, for the Rate 1 and 6 average use regression equations. Tables 4 and 7 in the same Exhibit, at pages 11 and 15 respectively present the mnemonics used in the models.

The models are in logarithmic form. The coefficients of the explanatory variables measure the change in average use resulting from a change in the explanatory variables, all else equal. The magnitude of the coefficient determines the extent of the explanatory variable's impact on the average use forecast for an equal percentage change in an explanatory variable.

Central Region - Central Weather Zone

Long Run Equation

Coefficient	t-Statistic	p-Value
0.62	0.80	0.43
0.71 -0.02	-1.62	0.00 0.12
0.58 0.22	8.53 2.51	0.00 0.02
-0.04	-3.73	0.00
0.00		
0.99		
0.01 645.70		0.000
	0.62 0.71 -0.02 0.58 0.22 -0.04 0.99 0.99	0.62

Witnesses: M. Suarez

H. Sayyan

Exhibit I.C2.EGDI.BOMA.13

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The table above replicates the Rate 1 Central region long run equation model presented in the pre-filed evidence. Interpretation of the explanatory variable coefficients is as follows: For example, the coefficient of REALCRCRPG- the real gas price variable (-0.02) is interpreted as follows: 1% increase in real gas price would lead to a 0.02% decline in average use for Central region Rate 1 customers assuming all other variables in the model are held constant. Similarly the coefficient of CDD-central degree days (0.71) shows that 1% increase in the Central region heating degree days would cause 0.72% increase in Central region Rate 1 average use.

This interpretation applies to all coefficients in the models except for the constant and dummy variables. The constant coefficient is just that, a constant and does not vary. The dummy variable is either 0 or 1.

Where included in a model the time trend takes on values, beginning with the value 1, to the end of the sample period. Time trend is a variable which is equal to the time index in a given year (if the sample includes years 1985-2016 then the time trend variable equals 1 for 1985, 2 for 1986 etc.). The coefficient for the time trend is interpreted in the same manner as the other coefficients (with the exception of the dummy variables and the constant). It should be noted, however, that the percentage change in the time trend decreases the longer the forecast horizon.

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

Witnesses: M. Suarez H. Sayyan

Exhibit I.C2.EGDI.BOMA.14

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BOMA INTERROGATORY #14

INTERROGATORY

Ref: Ibid, p20

Is a constant basis used between Hub price forecasts and gas prices in the basins from which EGD obtains its gas? What are those bases?

RESPONSE

The Henry Hub price is the benchmark for North American natural gas prices, and as such, is commonly forecasted, providing a good reference from which to obtain a consensus. In addition, it is highly correlated with the prices found at various basins including those from which EGD sources its supply. EGD found that the correlation coefficients between Henry Hub prices and prices at AECO, Dawn and Chicago Hubs tend to be above 0.95. It is for these reasons that the consensus forecast at Henry Hub is used for commodity pricing. No other bases calculations are required.

Once EGD establishes the consensus forecast of Henry Hub prices, the year-over-year change is calculated and applied to the last year of actual commodity charge. If year-to-date actual commodity charges are available those will also be used in the forecast. For example, actual commodity charges from the January 2017 and April 2017 QRAM rates were available to calculate the 2017 forecast of commodity charges so an average of half year actual percentage change and half year forecast percentage change (based on Henry Hub consensus) was used to forecast 2017 commodity charges. After the commodity price forecast is established, EGD then layers on distribution, transportation, and customer charges using the Company's latest available QRAM rates to arrive at the burner tip gas price forecast.

Witness: M. Suarez

Exhibit I.C2.EGDI.BOMA.15

Page 1 of 1

BOMA INTERROGATORY #15

INTERROGATORY

Ref: Ibid, p22

What is the current average furnace efficiency across the EGD service territory, in each of its weather zones?

RESPONSE

The last comprehensive Residential survey of the EGD franchise area was performed in 2013. Results showed the following furnace efficiency breakdown by region:

Furnace Efficiency	Weather Zones				
(customer reported)	Central	Eastern	Niagara		
Conventional (less than 75% efficiency)	6.5%	4.1%	4.6%		
Mid-Efficiency (75-90% efficiency)	27.2%	22.1%	33.0%		
High-efficiency (over 90% efficiency)	51.7%	57.2%	54.8%		
Unknown	14.6%	16.6%	7.6%		

Notes: Sample size: 2,506. Overall margin of error is 1.7 percentage points, at 95% confidence.

Witness: M. Suarez

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C2.EGDI.EP.3 Page 1 of 1

EP INTERROGATORY #3

<u>INTERROGATORY</u>

Reference: Exhibit C2 Tab 2 Schedule 1 Page 23 para 29

Preamble: The Company has observed progressively higher energy content values over the past few years as a result of gas supplies from Marcellus-Utica taking up a larger share of gas supply. The average use forecast relies on historical average uses that have inherently lower/higher heat values than what would have been in effect in the test year due to the different mix of supplies. That is, volumes in the test year would, on average, have had a higher/lower effective energy content than what would have been implicit in the forecast, thereby possibly requiring lesser/greater volumes than anticipated to meet normalized energy requirements.

- A). Please clarify if the Average Use Models as per the 2017 Settlement Agreement used the updated heat value of 38.42 MJ/m3 cited in the Gas Supply Plan and Exhibit D1 Tab 2 Schedule 11Page 13 paragraph 39.
- B). If not, please provide a table showing the heat values used for each Zone for the 2018 NAC forecast and indicate the basis of the estimates.

RESPONSE

a) & b)

Historical actual average use volumes are used as the dependent variables in the average use models. The actual volumes embody the actual blend of heat values inherent in the gas supplies over the course of the year. As such, no adjustment was made to the heat value; actual volumes reflect actual heat values as experienced. The 2018 forecast of average use demand is a volumetric measure that reflects the historical blend of heat values.

Witnesses: H. Sayyan

M. Suarez

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C2.EGDI.EP.4

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EP INTERROGATORY #4

<u>INTERROGATORY</u>

References: Exhibit C1 Tab 2 Schedule 1 Page 9,

Exhibit C2 Tab 2 Schedule 1 Page 23 Exhibit C2 Tab 1 Schedule 3 Page 7.

Preamble: The rate of actual average use decline in 2016 was an anomaly as it was not consistent with the historical trend, declining from 2015 by -3.2%. No significant development occurred in 2016 that would allow direct causal inference with 2016 results. As a result, the Company is inclined to treat the 2016 experience as an anomaly until additional, similar actual observations constitute an indication of trend. This treatment is confirmed through diagnostic testing of econometric models as further detailed in the Average Use Evidence at Exhibit C2 Tab 1 Schedule 3 on page 7.

- A). Please provide for the residential class for each of the 3 heating degree zones, charts showing the forecast and/or actual average use, for 2007 to 2017 and forecast 2018.
- B). Please explain the structural change/result in increased average use in 2016 for the residential class.
 - In terms of contributing causes (including those discussed at Exhibit C2 Tab 2 Schedule 1 Page 23
 - In terms of the Average Use Model and Statistics Exhibit C2 Tab 1 Schedule 3
- C). Please provide the actual degree days and Normalized Average Use occurring in winter 2016/17.
- D). Compare to prior years 2007-16 and to 2018 forecast.

Witnesses: R. Cheung

Filed: 2017-11-13 EB-2017-0086 Exhibit I.C2.EGDI.EP.4

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RESPONSE

a) The table on the following page shows the Actual and Board-Approved average uses by the three weather zones along with the degree days, for the years from 2007 to 2018.

The table has been expanded to include responses to part c) & d).

The response to part b) is on page 4.

Witnesses: R. Cheung

Exhibit I.C2.EGDI.EP.4

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TABLE 1
GENERAL SERVICE AVERAGE USE AND DEGREE DAYS

		Actual	Board-Approved	Normalized		
Test Year	Weather	Normalized	Normalized	Average Use Variance	Actual Degree	Board-Approved
	Zones	Average Use	Average Use	(m³)	Days	Degree Days
		(m³)	(m³)	(m)		
	Central	2,814	2,771	43	3,613	3,617
2007	Eastern	2,458	2,435	23	4,361	4,410
	Niagara	2,392	2,356	36	3,313	3,546
	Central	2,720	2,736	(16)	3,750	3,543
2008	Eastern	2,364	2,371	(7)	4,369	4,321
	Niagara	2,341	2,316	25	3,469	3,472
	Central	2,700	2,715	(15)	3,764	3,514
2009	Eastern	2,386	2,403	(17)	4,472	4,363
	Niagara	2,259	2,336	(77)	3,527	3,435
	Central	2,670	2,705	(35)	3,454	3,546
2010	Eastern	2,337	2,411	(74)	3,979	4,390
	Niagara	2,184	2,240	(56)	3,316	3,433
	Central	2,689	2,727	(38)	3,597	3,602
2011	Eastern	2,311	2,432	(121)	4,108	4,421
	Niagara	2,239	2,241	(2)	3,344	3,447
	Central	2,630	2,597	33	3,194	3,532
2012	Eastern	2,219	2,270	(51)	4,048	4,343
	Niagara	2,166	2,153	13	3,013	3,418
	Central	2,661	2,687	(26)	3,746	3,668
2013	Eastern	2,210	2,192	18	4,484	4,297
	Niagara	2,121	2,174	(53)	3,537	3,420
	Central	2,571	2,543	28	4,044	3,517
2014	Eastern	2,190	2,089	101	4,552	4,243
	Niagara	2,130	2,091	39	3,814	3,386
	Central	2,527	2,516	11	3,710	3,536
2015	Eastern	2,133	2,134	(1)	4,397	4,267
	Niagara	2,075	2,066	9	3,548	3,376
	Central	2,504	2,588	(84)	3,412	3,617
2016	Eastern	2,102	2,174	(72)	4,231	4,323
	Niagara	2,035	2,084	(49)	3,233	3,408
	Central		2,584			3,639
2017 Board-	Eastern		2,162			4,341
Approved ¹	Niagara		2,047			3,405
	Central		2,463			3,642
2018 Proposed	Eastern		2,081			4,331
	Niagara		1,985			3,421

Note

1. 2017 Board-Approved average use provided in lieu of actual average use as partial year information is not indicative of full year results.

Witnesses: R. Cheung

Exhibit I.C2.EGDI.EP.4

Page 4 of 4

b) It is acknowledged that contributing factors like heat content impacts, Building Code effectivity, and changes in customer behavior may have influenced 2016 results. However, these factors cannot be evaluated in such a way as to constitute measurable, definitive explanations for the actual usage variances.

The Company has observed progressively higher energy content values over the past few years as a result of gas supplies from Marcellus-Utica taking up a larger share of sendout. The average use forecast relies on historical average uses that have inherently lower heat values than what would have been in effect in 2016 due to the different mix of supplies. That is, volumes in 2016 would, on average, have had a higher effective energy content than what would have been implicit in the forecast, thereby possibly requiring lesser volumes than anticipated to meet normalized energy requirements. While this understanding would help explain the directional difference in average use, it cannot explain the magnitude.

Similarly, when the 2016 forecast was developed, 2014 volumes constituted the last full year of actual values. In January 2014, the 2012 Building Code came into effect, and its impact would have had partial effectivity in the actual 2014 volumes included in the historical sample. The Company surmises that 2016 actual volumes likely reflect the fuller impact of those code changes, contributing to average use reductions that were deeper than anticipated.

Finally, customer behavior is the most difficult factor to assess or predict. It is possible that volatile natural gas prices from 2014 and 2015 may have contributed to a shift in consumption patterns in the winter months. Also, government proposals in 2016 to transition away from natural gas usage, coupled with Cap and Trade discussions. could have created uncertainty in the continued viability of natural gas as a fuel source for consumers.

As noted in Board Staff Interrogatory #6, at Exhibit I.C2.EGDI.STAFF.6 and Exhibit I.C2.EGDI.EP.5, diagnostic testing is used to assess the reliability of the econometric models. Where models fail the diagnostic tests, model modifications are made to ensure the results can be interpreted with confidence. The Chow Test assesses whether a structural break (outliers, level-shifts, or temporary changes) has occurred. Test results are shown in Tables 6 and 9 (Exhibit C2 Tab 1 Schedule 3, pages 14 and 19, respectively) which confirm that a structural break is evident for Metro region revenue class 20 (Rate 1) and Eastern region revenue class 73 (Rate 6) models. The Company included dummy variables in those models to suppress the likelihood of a similar off-trend result in 2016 being forecast for 2018.

c) & d) Actual average use and degree days included in same table as in part a)

Witnesses: R. Cheung

Exhibit I.C2.EGDI.FRPO.4

Page 1 of 1

FRPO INTERROGATORY #4

<u>INTERROGATORY</u>

REF: Exhibit C2, Tab 1, Schedule 2, page 6

Preamble: We would like to understand better the mechanics behind the calculation of the Gas Supply degree days. The above reference contains the following description of this value: "On the other hand, Gas Supply degree days are determined relative to average hourly temperatures within a 24-hour period."

Please explain how the Gas Supply degree days are determined (over what time frame, through what approach, etc.).

- a) Please specify the source of the data for hourly temperatures if used.
- b) Are the locations for temperature data the exact same as those used by Environment Canada?

RESPONSE

- a) The Company sets its volumes budget using daily Gas Supply degree days that are provided by Gas Control for each region. Gas Control receives hourly temperature data information from an independent weather service who provides data based on the gas day i.e., 10:00am to 10:00 am
- b) The independent weather service uses information provided by Environment Canada for the locations identified in Exhibit C2, Tab 1, Schedule 2, footnote 1 in Table 2, 4 and 6 on pages 2, 4, and 6

Witness: M. Suarez

Exhibit I.C2.EGDI.VECC.4

Page 1 of 1

VECC INTERROGATORY #4

INTERROGATORY

Reference: Exhibit C2/T1/S1/pg.1

Preamble: The actual Canadian inflation rate for 2017 as measured either monthly (January-Sept) or annual Sept 2016 –Sept 2017 is between 1.54% and 1.55% (see for example http://www.inflation.eu/inflation-rates/canada/historic-inflation/cpi-inflation-canada-2017.aspx). This would appear to make the forecast of 2017 inflation rate (shown in table) of 2.1% highly improbable.

- a) If EGD were to assume an inflation factor of 1.6% for 2017 and 2018 what difference would this make to the 2018 rate proposal?
- b) What would be impact on average use based on the conversion of nominal to real prices in the average use modelling (see E2/T2/S1/pg.20/par 19) if the lower inflation figure were adopted?

RESPONSE

a) & b) Based on an updated Ontario outlook (2017 Q3) provided in response to BOMA #9 at Exhibit I.C2.EGDI, inflation is expected to be 1.6% in 2017 and 1.8% in 2018. This is lower than the inflation forecast (2.1% in 2017 and 2.0% in 2018) that was used to determine real gas prices which is a driver variable in the models. A lower inflation forecast would have resulted in higher real gas prices which would have produced a slightly lower average use forecast for both Rate 1 and Rate 6. It is estimated that the Company's volumetric budget for General Service customers would have been approximately 0.01% lower (about 1 million m³) than the proposed budget of 9,590.3 million m³ had the currently updated inflation forecasts been used.

Witness: M. Suarez

Exhibit I.D1.EGDI.STAFF.7

Page 1 of 2

BOARD STAFF INTERROGATORY #7

INTERROGATORY

Ref: Operating Costs – Gas, Transportation and Storage Costs Exhibit D1 / Tab 2 / Schedule 3 / Page 4

Preamble:

Enbridge noted that, for the purposes of its 2018 rates application, it has assumed the originally planned in-service date for NEXUS of November 1, 2017 and therefore the pipeline would be fully in place for the 2018 calendar year. Enbridge is aware however, that the in-service date has been recently delayed to 2018 as a result of NEXUS not receiving Federal Energy Regulatory Commission ("FERC") approval due to a lack of voting quorum. At this time the length of a delay is unknown. In order to mitigate the impact of the NEXUS in-service delay, Enbridge will continue to fill its Vector capacity with supply from Chicago until the contracted capacity on NEXUS comes into service. Enbridge proposed that any variances associated with a delay will be captured as a part of the 2018 PGVA.

Question(s):

- a) Please advise whether Enbridge has an estimate with respect to the length of the expected delay to the NEXUS in-service date.
- b) Please confirm that, on an actual basis, there are no costs incurred by Enbridge with respect to NEXUS until such time that the pipeline is placed in-service.
- c) Please explain why Enbridge has continued to assume that NEXUS will be placed inservice during 2018 for the purposes of its gas supply plan. Please discuss why Enbridge has not removed NEXUS from its plan and replaced it with the gas supply and transportation that Enbridge will likely use on an actual basis.

RESPONSE

- a) The most recent communication that Enbridge has received indicates an in-service date of September 1, 2018 for the Nexus Pipeline.
- b) Confirmed. Enbridge will only incur costs with respect to Nexus once the pipeline is in service.

Exhibit I.D1.EGDI.STAFF.7

Page 2 of 2

c) As described at Exhibit D1, Tab 2, Schedule 3, page 4 of 16, the 2018 gas supply plan assumes that the Company will be acquiring gas throughout 2018 in the Kensington area at the interconnect to the Nexus Pipeline and transporting that supply to the Vector interconnect at Milford Junction and then from there via the Vector pipeline to Dawn. Absent the Nexus Pipeline being in service, EGD will procure the equivalent amount of supply in the Chicago area and transport that supply to Dawn via the entire Vector path – Chicago to Dawn.

As described above, the current estimate is that Nexus will be in-service sometime during 2018. The exact date is unknown at this time. As the Company has described, regardless of the in-service date of the Nexus Pipeline the Company is forecasting to receive a total of 175,000 Mmbtu/day via Vector at Dawn as a part of its 2018 supply plan.

The Company's believes that it is appropriate to leave the gas supply plan as filed for purposes of the derivation of the reference price within the 2018 QRAM applications, rather than estimating an in-service date for Nexus. As stated at Exhibit D1, Tab 2, Schedule 3, page 4 of 16, any variances – both commodity and transportation – associated with a delay in the in-service date will be captured in the 2018 Purchase Gas Variance Account ("2018 PGVA").

Exhibit I.D1.EGDI.STAFF.8

Page 1 of 2

BOARD STAFF INTERROGATORY #8

<u>INTERROGATORY</u>

Ref: Operating Costs – Gas, Transportation and Storage Costs Exhibit D1 / Tab 2 / Schedule 3 / Page 5 Exhibit D1 / Tab 2 / Schedule 7

Preamble:

Enbridge stated that the impact of Direct Purchase customers shifting from Western or Ontario T-Service to Dawn T-Service is twofold: firstly, peak day deliveries to the franchise area via Ontario T-Service customers will decline (Line 8 of the Peak Day Supply Mix schedule); secondly, the Company needs to increase volumes delivered to the franchise area to replace the decline in volume delivered by Ontario T-Service customers (currently that deficiency is mostly visible as an increase in Peaking Service in Line 11 of Schedule 7).

Question(s):

a) At Line 11 of Exhibit D1 / Tab 2 / Schedule 7, there seems to be a decline in Peaking Service as between 2018 and 2017. Please explain the apparent discrepancy between Schedule 7 and the statement copied above.

RESPONSE

When comparing the forecasted peaking requirement between 2018 and 2017 in the CDA there is a small decline (29,080 10³m³ in 2017 vs. 26,560 10³m³ in 2018) which is counter to the description provided in evidence.

The evidence was intended to identify the impact on peak day once all OTS and WTS pools convert to DTS. Effective November 1, 2017, customers will have an opportunity to convert their pools from OTS/WTS to DTS upon their pool renewal date.

The information provided in line 8 of the Peak Day Supply Mix Schedule provides the forecasted decline in OTS delivery volumes in 2018 versus 2017 (209,846 10³m³ in 2017 vs. 84,264 10³m³ in 2018 in the CDA) on peak day which for planning purposes is deemed to be in the month of January. Conversion of OTS / WTS to DTS pools will continue throughout 2018 such that the expectation is that by November of 2018, the amount of

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.8

Page 2 of 2

OTS volumes delivered to the CDA will be almost zero. Should this forecast come to fruition then there will be an increase in the peaking service requirement in the future.

Exhibit I.D1.EGDI.STAFF.9

Page 1 of 2

BOARD STAFF INTERROGATORY #9

INTERROGATORY

Ref: Operating Costs – Gas, Transportation and Storage Costs Rate Design – Gas Supply Revenues Exhibit D1 / Tab 2 / Schedule 3 / Page 9 Exhibit H1 / Tab 1 / Schedule 1 / Page 8

Preamble:

Enbridge noted that the July 1, 2017 rates have a Purchased Gas Variance Account (PGVA) reference price of \$188.611 / 103m3. The PGVA reference price is comprised of commodity, transportation and load balancing costs. Enbridge stated that "aligned with the Minimum Filing Requirements, in order to limit the impacts of the new gas supply portfolio on the proposed 2018 rates, the Company based the cost of the 2018 portfolio on the July 1, 2017 QRAM reference price of \$188.611 / 103m3."

Question(s):

- a) Please explain the statement, "aligned with the Minimum Filing Requirements, in order to limit the impacts of the new gas supply portfolio on the proposed 2018 rates, the Company based the cost of the 2018 portfolio on the July 1, 2017 QRAM reference price of \$188.611 / 103m3." In the response, please include a reference from the Minimum Filings Requirements that is the basis for this statement.
- b) Please advise whether the methodology used to establish the cost of the 2018 gas supply portfolio is different than what has been approved in the previous years of the current Custom IR term. If so, please explain the reason for the change, discuss the typical methodology utilized and provide the reference price that would have been applied arising from the typical methodology.

RESPONSE

a) and b)

The OEB's Minimum Filing Requirements for Gas Distributors (EB-2005-0494, pages 3 and 4) state with respect to gas costs:

Witnesses: J. Collier

A. Kacicnik

D. Small

Exhibit I.D1.EGDI.STAFF.9

Page 2 of 2

The Board's minimum filing requirements have been designed in a manner to try to isolate the delivery related sufficiency / deficiency separate and apart from the commodity related sufficiency / deficiency. In keeping with that, utilities should provide revenue sufficiency or deficiency calculations net of gas commodity price changes captured in the QRAM. When filing, the commodity cost will be that available from the most recent Board approved QRAM, at the time of filing.

The methodology that the Board approved in the previous years of the current Custom IR term to establish the cost of the gas supply portfolio consists of applying commodity and transportation prices / tolls from the most recent Board approved QRAM to the new / proposed gas supply portfolio and associated volumes.

When the Company applied the same methodology to establish the cost of the 2018 gas supply portfolio as the Board approved in the previous years of the current Custom IR term, the methodology resulted in a 2018 PGVA reference price of approx. \$185.6 / 10³m³ (versus the July 1, 2017 QRAM PGVA reference price of \$188.611 / 10³m³).

In the Company's view, the approx. \$3 / 10³m³ difference in the derived PGVA reference price is due to year-over-year changes in the gas supply portfolio (i.e. change in the mix of supply and transportation arrangements).

The use of the 2018 PGVA reference price of approx. \$185.6 / 10³m³ would create a material gas cost sufficiency of about \$25 M, which, in the Company's view, would run contrary to the Board's minimum filing requirements which were put in place to try to isolate the delivery related sufficiency / deficiency separate and apart from the commodity related sufficiency.

In other words, the overall proposed 2018 deficiency would be about \$25 M lower than the applied for 2018 revenue deficiency of about \$86 M.

The Company, therefore, in order to limit the impacts of the new gas supply portfolio on the proposed 2018 delivery rates, based the cost of the 2018 portfolio on the July 1, 2017 QRAM reference price of \$188.611 / 10³m³.

It is important to note, however, that while the Company based the cost of the 2018 portfolio on the July 1, 2017 QRAM reference price of \$188.611 / 10^3 m³, the impacts from the 2018 supply portfolio will flow to customers through the January 1, 2018 QRAM.

Witnesses: J. Collier

A. Kacicnik

D. Small

Filed: 2017-11-13
EB-2017-0086
Exhibit I.D1.EGDI.STAFF.10
Page 1 of 3
Plus Attachment

BOARD STAFF INTERROGATORY #10

<u>INTERROGATORY</u>

Ref: Operating Costs – Gas Supply Future Considerations Exhibit D1 / Tab 2 / Schedule 11 / Pages 12-13

Preamble:

In the EB-2016-0142 proceeding, Enbridge agreed that "before the Company develops or acquires additional storage capacity for utility or regulated gas supply purposes it will file analysis with the Board setting out the need and justification for the incremental storage". In the EB-2016-0215 proceeding, Enbridge agreed to file a copy of the study then being prepared by ICF International concerning Enbridge's future storage requirements.

In March 2017, the Company filed the report developed by ICF International which evaluated incremental storage options that the Company might pursue.

At this time, as set out in the gas supply evidence in this proceeding, Enbridge is planning to acquire between 2 and 3 PJ of additional storage in April 2018. Furthermore, from time to time, the Company will consider shorter term high deliverability seasonal exchanges that provide operational flexibility to meet winter demand.

Question(s):

- a) Please file a copy of the ICF International Report on the current record.
- b) Please confirm that EGD's decision to acquire incremental storage capacity is in accordance with the ICF International Report. Please provide specific references from the noted report that support Enbridge's decision.
- c) Please provide a detailed explanation setting out the need and justification for the incremental storage.
- d) Please discuss the future implications on Enbridge's gas supply plan of a potential amalgamation with Union Gas Limited. Please advise when detailed evidence with respect to this issue will be filed.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.10 Page 2 of 3 Plus Attachment

RESPONSE

- a) See attached.
- b) EGD's decision to acquire incremental storage capacity is in accordance with ICF International's report. Specific references from the report which support EGD's decision include:
 - a. ICF's conclusion related to the impact incremental storage capacity has on Enbridge's gas supply portfolio costs (pp. 38):

In all of the scenarios, the increase in storage capacity allows Enbridge to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher.

b. ICF's conclusion related to the impact incremental storage capacity has on Enbridge's long-term average costs (pp. 44):

If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of between and 20 Bcf of incremental storage capacity.

If incremental storage costs increase by 50 percent relative to existing contracted storage costs, ICF would recommend consideration of about 20 Bcf of incremental storage capacity.

c. ICF's conclusion related to the impact incremental storage capacity has on Enbridge's cost consequences related to colder than budgeted weather (pp. 45):

If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

An increase in incremental storage costs of 50 percent relative to existing contracted storage costs would not change the recommendation. ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.10

Page 3 of 3 Plus Attachment

c) As discussed at Exhibit D1, Tab 2, Schedule 3, page 7 of 15, paragraph 21 the Company is forecasting a purchase requirement of Delivered Supplies at Dawn of 92.2 Bcf with 58.9 Bcf required during the winter months. The Company also stated in paragraph 23 of the same exhibit that until 2021 the Company does not see a material change in its winter requirement at Dawn. Therefore, the Company believes that acquiring incremental storage would allow the Company to purchase more gas during the summer thereby taking advantage of the summer-winter Dawn spread. See bullet point a) in response to part b) above.

d) The amalgamation proposal of Enbridge and Union Gas was filed with the OEB on November 2, 2017, and the proposal will be reviewed within that proceeding (under the file number EB-2017-0306 assigned by the OEB).



Exhibit 1.D1.EGDI.STAFF.10

Attachment Page 1 of 64

Enbridge Gas Storage Assessment

Potential Value of Incremental Storage Capacity for Enbridge Gas

January 26th, 2017

Submitted to: Enbridge Gas Distribution Submitted by:

ICF Resources, L.L.C.

9300 Lee Highway

Fairfax, VA 22031

Filed: 2017-11-13 EB-2017-0086 Exhibit 1.D1.EGDI.STAFF.10 Attachment Page 2 of 64

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1. Summary

1.1 Purpose

In 2015, the Ontario Energy Board approved changes to Enbridge Gas Distribution Inc. (Enbridge or the Company)'s storage deliverability targets, extending the January maximum deliverability maintained by the Company to the end of February, and extending the maximum March deliverability to the end of March.

These changes in storage deliverability targets were made to reduce the possibility of situations similar to the winter of 2013/14, when low storage inventories at the end of the winter necessitated the purchase of additional gas supplies from Dawn during high price periods. The change in deliverability targets results in a shift in gas supply purchases to earlier in the winter season, providing additional flexibility later in the year, and allowing Enbridge to minimize future rate impacts on Enbridge customers due to late season price spikes.

In order to meet the new deliverability targets, the Company's gas supply plan has been altered to shift the timing of gas supply purchases. To meet these new targets, Enbridge has increased its early winter season supply purchases to offset storage withdrawals and maintain a higher storage balance later into the winter, which will reduce late winter season purchases. Enbridge also began to consider the acquisition of incremental storage capacity to allow shifting of incremental natural gas purchases to lower priced periods, and to further reduce the volatility in delivered natural gas prices to its customers.

Prior to acquiring incremental storage, Enbridge agreed to perform a detailed review of the need for incremental storage with the support of an external consultant. As a result of this agreement and the changes in storage deliverability targets, Enbridge requested the assistance of ICF to determine whether a reduction in overall Enbridge natural gas supply costs could be achieved by acquiring incremental storage space within the Company's gas supply plan.

1.2 Structure of Report

This report documents the results of ICF's market analysis and storage value analysis, and provides an assessment of the reduction in expected natural gas supply portfolio costs that Enbridge should expect to see should additional storage capacity be added to the Company's gas supply portfolio. The remainder of **Section 1** provides an overview of the analysis and a summary of results. **Section 2** of this report provides a broad overview of the current Enbridge storage portfolio and approach to evaluating storage requirements. **Section 3** of this report reviews the results of the ICF review of storage practices by other similarly situated natural gas distribution companies. **Section 4** of this report provides an overview of the key market trends expected to determine storage value and utilization in the future. **Section 5** documents the

¹ Enbridge Gas Distribution Ontario Energy Board Case EB-2015-0122



Exhibit 1.D1.EGDI.STAFF.10

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approach used in the storage analysis, and provides the results of ICF's analysis and recommendations for Enbridge future storage capacity.

1.3 Overview of Approach

ICF used its April 2016 Gas Market Model (GMM) as the starting basis for its evaluation of the North American natural gas markets and Enbridge's gas storage operations. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix D. ICF used the GMM to conduct sophisticated analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.

Development of Weather Scenarios

In order to assess the value of natural gas storage for Enbridge under different weather scenarios, ICF used the GMM to develop three alternative price scenarios reflecting Enbridge's planning scenarios for Budgeted Weather, Colder than Budgeted Weather, and Warmer than Budgeted Weather. The alternative weather scenarios were developed for the 3-year period from April 2017 through March 2020. For each weather scenario, Enbridge's daily load profile includes the company's peak day design criteria, which includes 18 separate peak days that are designed to mimic the coldest temperatures expected over the winter season. Enbridge's Peak Design Day is based on a 1 in 5 recurrence interval derived from a lognormal distribution of Heating Degree Days (HDDs).

In order to develop the three different weather scenarios, ICF ran the GMM iteratively using 85 sets of actual 3-year weather patterns to assess the potential impact of weather on demand and prices in order to project demand and gas prices. The use of actual weather scenarios is an important consideration to allow for a more complete assessment of the actual range of impacts due to the range of positive and negative correlations between the weather patterns of different regions across North America.

Using the 85 unique three year weather scenarios, ICF developed three separate scenarios; a Warmer than Budgeted case, a Budgeted Weather case, and a Colder than Budgeted case. The three Enbridge weather scenarios (Colder, Budgeted, and Warmer) were constructed to best approximate Enbridge's HDD forecast for each of its weather planning scenarios. Each of these three weather scenarios were crafted from an average of four unique weather cases selected from the larger set of 85 weather cases. These four weather cases for each scenario were selected to develop a composite scenario that most closely aligned with Enbridge's three planning scenarios.

² Enbridge Gas Distribution 2017 Rate Case Application EB-2016-0215, Exhibit D1



Exhibit 1.D1.EGDI.STAFF.10

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Enbridge's Budgeted Weather scenario assumptions are determined by the company's Economics and Business performance department, which utilizes an OEB approved methodology to determine the level of HDDs to be used in gas supply planning. For the purpose of this analysis, the Colder than Budgeted weather scenario reflects a winter with daily average weather 10 HDDs colder than the Budgeted weather scenario. The Warmer than Budgeted scenario reflects a winter with daily average weather 10 HDDs warmer than the budgeted weather conditions.

The resulting commodity price and demand outlooks across the Colder than Budgeted, Budgeted, and Warmer than Budgeted weather cases were used by Enbridge to assess the impact of alternative storage scenarios on Enbridge's natural gas supply portfolio costs using the Enbridge SENDOUT© model. The storage scenarios include five different levels of storage capacity, and two different storage cost scenarios.

Exhibit 1-1: Dawn Prices (US\$) Under the Three Enbridge Weather Scenarios

Source: ICF Gas Market Model

ICF used the results of the Enbridge SENDOUT© analysis to assess the impact on Enbridge supply portfolio costs of the alternative storage scenarios and weather scenarios to determine the potential costs and benefits of increasing the amount of storage capacity used by Enbridge Gas.

1.4 Summary of Conclusions

ICF analyzed the SENDOUT© optimization results prepared by Enbridge in order to evaluate the impact of the alternative price scenarios on Enbridge supply purchases under five different storage capacity cases, ranging from the current level of storage capacity up to an additional 20



Exhibit 1.D1.EGDI.STAFF.10

Bcf of incremental storage capacity,³ and for two different storage cost scenarios in order to assess the potential reduction in gas portfolio costs resulting from the addition of incremental storage capacity to Enbridge's gas supply portfolio.

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Considering the current cost of storage capacity available from third parties, supply portfolio costs are minimized by adding at least 20 Bcf of incremental storage capacity to the Enbridge supply portfolio in the Colder than Budgeted and Budgeted Weather scenarios, and up to 20 Bcf of storage capacity in the Warmer than Budgeted Weather scenario.

Raising the incremental cost of storage capacity by 50 percent relative to existing levels has minimal impact on the amount of additional storage capacity that would be economic in the Budgeted and Colder than Budgeted weather scenarios. At the higher storage cost the Enbridge supply portfolio cost would be minimized by adding at least 20 Bcf of storage capacity in the Colder than Budgeted scenario, and the Budgeted Weather scenario. Under the higher storage cost assumptions the Enbridge supply portfolio cost would be minimized by adding up to 15 Bcf of storage capacity.

The overall results of the three year period from April 2017 through March 2020 of all weather, demand, and storage cost scenarios are shown in Exhibit 1-2.

Exhibit 1-2: Average Annual Change in Total Gas Costs from Incremental Storage Capacity From Enbridge SENDOUT© Results

Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020					
(CAD\$Millions)	Reference Storage Costs	50 Percent Increase in Storage Costs			
Colder than Budgeted V	Veather Scenario				
5 Bcf	-12.3	-9.7			
10 Bcf	-24.4	-19.3			
15 Bcf	-36.7	-29.0			
20 Bcf	-47.6	-37.3			
Budgeted Weather Scer	nario				
5 Bcf	-3.2	-0.6			
10 Bcf	-6.1	-1.0			
15 Bcf	-9.0	-1.3			
20 Bcf	-11.7	-1.4			
Warmer than Budgeted Weather Scenario					
5 Bcf	-2.9	-0.3			
10 Bcf	-5.5	-0.4			
15 Bcf	-8.0	-0.4			
20 Bcf	-8.0	2.3			

Recommendations of Future Additions to Storage Capacity

³ The storage capacity scenarios were capped at 20 Bcf due to uncertainty of incremental storage availability at levels higher than 20 Bcf



Exhibit 1.D1.EGDI.STAFF.10

Based on the assessment of natural gas market trends, expected natural gas prices at Dawn, and the value of natural gas storage as part of the Enbridge overall supply portfolio, ICF's analysis of Enbridge's SENDOUT© results indicates that additional storage capacity across the three weather scenarios and both cost scenarios would reduce the expected overall cost of the Enbridge gas supply portfolio.

The overall amount of incremental capacity that should be considered by Enbridge will depend on the cost of the incremental storage, and the level of importance Enbridge places on minimizing the cost impacts of a colder than normal winter for its customers, relative to minimizing the long-term average cost.

A strategy designed to minimize the total long-term cost of the Enbridge supply portfolio to consumers would be heavily weighted toward the Budgeted Weather scenario based on the expected distribution of the weather scenarios given the likelihood of either the Warmer or Colder than budgeted scenarios. Based on a weighting of 60 percent for the Budgeted Weather scenario, and 20 percent (one year in five) for both the Colder than Budgeted and Warmer than Budgeted weather scenarios. (Exhibit 1-3) Under this set of priorities:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of to 20 Bcf of incremental storage capacity.
- If incremental storage costs increase by 50 percent relative to existing contracted storage costs, ICF would recommend consideration of 20 Bcf of incremental storage capacity.

A strategy designed to minimize the potential impact of a colder than normal winter on costs to Enbridge consumers would still weigh the Budgeted scenario most heavily, but would discount the Warmer than Budgeted scenario and over-weight the Colder than Budgeted scenario. The weighting of the different scenarios used to accomplish this objective is a policy judgement that will need to be made by Enbridge. For the purposes of this analysis, ICF has weighted the Colder than Budgeted Weather Scenario at 40 percent, the Budgeted Weather Scenario at 60 percent, and the Warmer than Budgeted Weather Scenario at 0 percent. (Exhibit 1-3) Under this set of priorities:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.
- An increase in incremental storage costs of 50 percent relative to existing contracted storage costs would not change the recommendation. ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

If incremental storage costs increase by more than the 50 percent increase relative to existing levels assessed in this analysis, ICF would recommend additional analysis be undertaken to ensure that the benefits of increasing storage capacity will exceed the incremental costs of the storage capacity.



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Exhibit 1-3: Average Annual Change in Total Gas Costs from Incremental Storage Capacity, Weighted by Weather Probability

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Average Annual Weighted Average Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020					
(CAD\$Millions)	Reference St	orage Costs		50 Percent Incre	ease in Storage Costs
Scenario	Balanced Cold Weather Weighting Weighting			Balanced Weighting	Cold Weather Weighting
Colder than Budgeted Weather Scenario	20%	40%		20%	40%
Budgeted Weather Scenario	60%	60%		60%	60%
Warmer than Budgeted Weather Scenario	20%	0%		20%	0%
Incremental Storage Capac	city				
5 Bcf	-4.9	-6.8		-2.4	-4.3
10 Bcf	-9.7	-13.4		-4.6	-8.3
15 Bcf	-14.3	-20.0		-6.6	-12.4
20 Bcf	-18.2	-26.1		-7.8	-15.8



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2. Enbridge Storage Operation Review

Enbridge Gas Distribution serves over 2.1 million customers, with its customer base divided into a Central weather zone, an Eastern weather zone and a Niagara weather zone. Enbridge currently owns and leases 114 Bcf of underground storage in southwestern Ontario and southeastern Michigan to serve Enbridge in-franchise customer gas supply requirements. This capacity includes 92 Bcf of utility-owned storage near the Dawn Hub, operated by Enbridge Gas Storage, along with contracts for an additional 22 Bcf of physical and "synthetic" storage capacity with other storage providers near the Dawn Hub.

Following the winter of 2013/14, which resulted in gas storage inventories being largely depleted toward the end of the heating season, Enbridge recommended changes in storage utilization to the Ontario Energy Board (OEB) as part of Enbridge's 2015 Rate Case Application (EB-2014-0276). The Based on this recommendation, the OEB approved changes to Enbridge's gas storage deliverability targets to be used in future gas supply plans and rate case applications. Modifications to the company's gas storage operations included adjustments to the gas storage deliverability targets to increase the levels of storage inventory maintained until the end of February and the end of March. The change in deliverability targets results in a shift in gas supply purchases to earlier in the winter season, providing additional flexibility later in the year.

The purpose of the changes in storage deliverability targets was to reduce the possibility of situations similar to the winter of 2013/14, when low storage inventories at the end of the winter necessitated the purchase of additional gas supplies from Dawn during high price periods, resulting in a significant and unexpected increase in delivered natural gas prices to Enbridge consumers.

ICF projects that over the next several years gas storage will become more important in balancing peak winter demand requirements as well as ensuring against a repeat of the winter of 2013/14. As the importance of gas storage operations increase, a review of the optimal level of gas storage and operating practices becomes a prudent step in Enbridge's gas supply planning process.

2.1 Summary of Enbridge's Gas Storage Operations

Prior to developing a gas supply plan, Enbridge conducts an annual design day and baseload day demand analysis over a five year planning horizon, with the primary focus being the first two years. A core purpose of these analyses is to determine the expected demand in future years, in order to evaluate the renewal, addition and shedding of transportation and/or other market-based solutions to meet that demand. Enbridge develops the gas supply plan over a two year planning horizon with the primary focus being on the first year. The two year planning horizon ensures that a complete storage management cycle is taken into account as the gas supply plan is developed.

In addition to establishing a cost-effective gas supply plan, Enbridge's gas supply planning process also considers diversity in gas supply sourcing, diversity in the type of gas storage



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utilized, system reliability, and system flexibility. Each of these factors are also influenced by the Attachment level of available gas storage and operating parameters.

2.1.1 Storage usage criteria

Enbridge's gas supply plan identifies planned injection and withdrawal volumes, storage balances, as well as a review of the costs for its storage facilities. The company manages its gas storage inventories to meet the following storage inventory guidelines:

- Required storage space is full by October 31.
- Sufficient inventory on February 28 to meet winter peak day storage withdrawal requirements.
- Sufficient inventory on March 31 to meet the March peak day storage withdrawal requirements.



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3. Review of Storage Operations in Other Jurisdictions Attachment Sage 15 of 64

As part of the review of Enbridge's gas storage operations, ICF was asked by Enbridge to review nearby regulated local gas distribution companies (LDCs) profiles, customer bases, gas storage assets, and how those companies manage their gas storage profiles in support of their gas supply strategies. This review was to serve as a benchmark for other storage practices and an understanding of how other LDCs manage their gas storage assets as part of their gas supply plans.

ICF reviewed public regulatory filings for LDCs in Ontario, Manitoba, Quebec, Michigan, Illinois, and Pennsylvania to complete this third party review. The regulated gas utilities reviewed are listed in Exhibit 3-1, and a summary of the storage practices for each utility is provided in the following sections. A more detailed review of each LDC's gas storage operations is included in Appendix A.

Exhibit 3-1: Summary Information on the Ten LDCs Reviewed

Utility	Number of Customers	2015 Gas Sales (Bcf)	Total Gas Storage Capacity (Bcf)
Enbridge	2,129,000	437	114 ⁴
Union Gas	1,437,000	490	163
Gaz Métro	195,000	202	19
Centra Gas Manitoba	270,000	74	15
Consumers Energy	1,700,000	350	150
DTE Gas	1,200,000	287	135
National Fuel Gas Distribution (NY & PA)	740,000	141	78
Peoples Gas	828,000	340	37
Ameren Illinois	816,000	160	~50
Nicor Illinois	2,000,000	>500	150
MidAmerican Energy	733,000	154	Not Reported

Source: Company Filings

3.1 Summary

Each LDC reviewed by ICF operates its gas planning process subject to the judgements of the regulating entity, the constraints and limitations of its access to natural gas pipelines, gas storage facilities, and the nature of its customer base. Despite differences across each LDC, each company utilizes a mix of gas storage and pipeline capacity agreements to balance the seasonal nature of their gas demand. The level of pipeline contracting, owned or contracted storage, and utilization of spot gas purchases vary significantly across each company and can have a large impact on the role that gas storage plays in meeting peak winter demand.

⁴ Enbridge holds 22 Bcf of 'physical and synthetic' contracted storage and 92 Bcf of gas storage at the Enbridge Gas Storage Facility to serve Enbridge Gas distribution customer requirements. The Enbridge Gas Storage Facility also includes 14 Bcf of gas storage capacity available to third parties.



Exhibit 1.D1.EGDI.STAFF.10

Storage capacity is generally utilized to allow LDCs to balance their daily gas demands over the Attachment winter periods and meet withdrawal requirements on peak design days. Gas storage operations are also used by some of the LDCs to minimize gas supply costs via increased levels of purchases in typically less expensive summer months, as well as to minimize the need for firm pipeline capacity agreements upstream of the storage capacity by having more uniform gas purchases. Gas storage is also used by some LDCs as part of price risk mitigation strategies, weighting increased levels of supply purchases toward less volatile summer periods.

Each company has an established target fill level and target storage fill date that corresponds to the beginning of that company's winter heating season. Six of the ten LDCs have a target for gas storage levels to be at 100 percent of capacity at the End of October. Two LDCs have a target for gas storage levels to be at 95 percent of capacity at the End of October and two LDCs have a target for storage levels to be 100 percent of capacity by November 15th.

Not all of the companies release publicly available information on storage utilization targets and target criteria. Where this information is available, it indicates LDCs will target an incremental drawdown in storage balances throughout the winter season. It is typical that LDCs make allowances throughout the heating season to make spot gas purchases as needed to maintain storage levels that will allow a company to meet storage withdrawal requirements of the company's Peak Design Day Demand throughout the winter period.

3.2 State Differences in Regulatory Approaches for Public Utility Commissions

The review of storage operations for other LDCs performed by ICF highlighted the large differences in the public reporting of storage operations, which are largely a function of the levels of details required by each utility's regulator. ICF reviewed storage operations for LDCs across three Canadian provinces and four states in the U.S., which were located in seven different jurisdictions of PUCs. There exist significant differences across these seven PUCs, which has a significant influence on the level of detail for each LDC's gas storage operations as well as a company's gas supply plan for manages its gas supplies to meet peak winter demands.

Most of the PUCs require regular filings and status updates on the LDC's gas supply plans and rate adjustments. Within these rate and gas plan regulatory filings there are varying levels of detail related to gas storage operations and the criteria governing the company's usage of gas storage assets. The Michigan Public Utility Commission (PUC) for instance, requires annual gas supply plans, which provide a high level of detail regarding monthly gas storage targets and inventory levels, while Illinois does not provide annual gas supply plans with the same level of detailed gas storage information.



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Exhibit 3-2: Public Utility Commission Summary

Utility Commission	Gas Utility	Summary
Régie de l'énergie (Quebec, Canada)	Gaz Métro	Limited ability to review public documents due to French Language reporting and a limited number of translated filings.
Ontario Energy Board	Union Gas, Enbridge Gas Distribution	Detailed review process with annual Gas Supply plans and quarterly rate adjustments. High level of detail included in regulatory documents for assessing gas storage operations.
Manitoba Public Utilities Board	Centra Gas Manitoba	Detailed review process with annual Gas Supply plans and quarterly rate adjustments.
Illinois Commerce Commission	Peoples Gas, Ameren Illinois, Nicor Illinois, MidAmerican Energy	The PUC uses an after the fact prudence review of LDCs gas supply plans. This provides significant flexibility for how companies manage storage inventory levels and pipeline contracts.
Michigan Public Service Commission	Consumers Energy, DTE Gas	LDCs must file gas supply purchase plans that dictate operational guidelines. Annual reconciliation reviews take place after the year.
New York Public Service Commission	National Fuel Gas Distribution	Provides for semi-automatic adjustment clauses in its rate filing process. The NY PUC will also allow for multi-year rate cases, limiting the quarterly and annual filing requirements.
Pennsylvania Public Utility Commission	National Fuel Gas Distribution	In addition to natural gas tariff filings, the PA PUC requires Winter Readiness plans that include information on gas supply planning.

Source: ICF, Public Utility Commission reports

3.3 Comparison of regulated Local Gas Distribution Utilities Gas Storage Operating Criteria

The following section includes several summary tables that compare different aspects of each LDC's gas storage operations in order to provide a benchmarking of Enbridge's gas storage operations. The information for these tables were developed through a review of publicly available information from regulatory proceeding filed with each state PUC. There are varying levels of information for each LDC making a full comparison difficult.

Of the ten LDCs reviewed, seven own their own storage capacity, with three companies (Gaz Metro, Centra Gas Manitoba, and MidAmerican Energy) relying solely on contracted storage capacity. LDCs that have their own gas storage assets will often contract for additional storage capacity, which can provide added flexibility to the company based on the type and availability of contracted storage near their service area.

Of the ten LDCs reviewed, seven have provided details on the storage deliverability and role of storage in meeting the company's Peak Design Day Demand. The absolute levels of storage deliverability varies widely, from 0.3 Bcfd to 2.5 Bcfd, and is largely dependent on the size of the LDC and the structure of demand in the company's service territory.

Storage deliverability typically plays a much larger role in meeting peak day demand, averaging 53 percent of peak demand, than in meeting average winter demand.



National Fuel Gas

Distribution (NY &

Peoples Gas

Nicor Illinois

Ameren Illinois

MidAmerican Energy

PA)

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Exhibit 3-3: Gas Utility Storage Operating Profile Comparison

Gas Utility Max Deliverability Storage % of Gas Storage Annual Storage Peak Design Peak Design Ownership Capacity (Bcf) from Storage **Day Demand** (Dth/d) **Day Demand** (Dth/d) **Enbridge** Yes 92 Bcf owned (with 2.180.000 3.811.000 57% 14 Bcf available to third parties) & 22 Bcf contracted storage **Union Gas** 152 1,718,000 3,276,000 52% Yes (95 in-franchise) 19.8 contracted Gaz Métro No 306,000 510,000 60% Centra Gas Manitoba No 14.7 contracted Yes 150 454,683 80% **Consumers Energy** 363,746 DTE Gas Yes 135.1 1,578,193 2,391,202 66%

78

36.5 (owned) &

contracted storage

24.6 (owned) &

contracted storage

150 (owned) & contracted storage

810,347

570,000

2,550,000

1,724,143

1,140,000

5.100.000

47%

36%

50%

50%

30-35%

Sources: ICF, LDC Regulatory Proceeding and Company Sources

Yes

Yes

Yes

Yes

No

Gas storage operations across the LDCs follow similar trends, with injections over the summer months sufficient to reach full inventories at the start of winter withdrawal seasons and inventory withdrawals over the course of the winter heating season. However, within these seasonal trends, there are some variations in how gas storage inventories are managed and the type of storage guidelines used. ICF has summarized these differences to highlight how Enbridge's guidelines compare to other LDCs practices.

Each LDC's gas storage guidelines plan to have storage inventory levels full at either the end of October or by November 15th. Three LDCs⁵ published monthly storage inventory targets as part of the regulatory filing process. Additional LDCs may also use monthly storage inventory targets but are not required to disclose this in regulatory filings. Enbridge's storage guidelines are to maintain sufficient inventory levels to maintain minimum deliverability targets at the end of February and end of March. Compared to monthly storage targets, this allows for more flexibility throughout the season than monthly inventory levels.

⁵ The Michigan LDCs include their monthly storage inventory and gas storage sendout volumes as part of the regulatory filings. This level of detail was not included in other PUC jurisdictions.



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Exhibit 3-4: LDCs Storage Capacity Targets

Gas Utility	Reported Storage Capacity (Bcf)	Date Storage Capacity to be Full	Type of Storage Guidelines
Enbridge	92 Bcf owned (with 14 Bcf available to third parties) & 22 Bcf contracted storage	End of October	Sufficient inventory at End of February to meet maximum withdrawal requirements
Union Gas	152 (95 in-franchise)	End of October	Sufficient inventory at End of February to meet maximum withdrawal requirements
Gaz Métro	19.8 contracted	End of October	Unknown
Centra Gas Manitoba	14.7 contracted on ANR	End of October	Unknown
Consumers Energy	175.6 (150 owned)	End of October	Monthly Storage Inventory Levels
DTE Gas	135	End of October	Monthly Storage Inventory Levels
National Fuel Gas Distribution (NY & PA)	78	96% Full at the End of October	Monthly Storage Inventory Levels
Peoples Gas		End of October	Unknown
Ameren Illinois	36.5 (owned) & contracted storage	Full Nov. 15th	Unknown
Nicor Illinois	26 (owned) / total of 36.5	Full Nov. 10th	Unknown
MidAmerican Energy	150 (owned) & contracted storage	End of October	Unknown

Sources: ICF, LDC Regulatory Proceeding and Company Sources

Five of the ten LDCs reviewed had publicly available details on how each company's gas storage is used and what factors are considered in daily and seasonal withdrawals. Several LDCs gas storage operations and withdrawals levels are designed to meet end of month target inventory levels and will have withdrawal volumes vary according to changes in weather and demand patterns, similar to Enbridge. Some LDCs manage their storage operations in less regulated manner, with only a beginning and ending target levels. While this may appear to have more flexibility, despite not having monthly targets throughout the winter, these LDCs typically have their own internal guidelines and storage operation criteria that can include factors like the level of contracted storage, nature of gas storage fields in use, minimizing costs of firm transport in winter months.



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Exhibit 3-5: Gas Utility Storage Usage and System Balancing

Gas Utility	Storage Operations Criteria	Key Factor for System Balancing
Enbridge	Targeted control points for storage levels; November 1 st is full; February 28 th has capacity to meet Design Day needs; March 31 st has capacity to meet March peak day.	Uses SENDOUT© model to optimize for the lowest-cost gas supply over the full year.
Union Gas	Targeted control points for storage levels, with allowances for integrity volumes; November 1st is full; February 28th has capacity to meet Design Day needs; Minimum levels of storage at end of March	Optimize for contracted upstream capacity to be utilized at 100% load factor.
Gaz Métro		
Centra Gas Manitoba		Gas storage to diversify supply sources
Consumers Energy	Beginning and end of season gas storage targets of 175.6 Bcf at end of October & 70.1 Bcf at end of March	Majority of gas purchases (75%) occur in the summer months
DTE Gas	Minimum levels of gas remaining in storage at the end of winter months	
National Fuel Gas Distribution (NY & PA)	Minimum levels of gas remaining in storage at the end of the month	Balance seasonal pipeline utilization and hedge against winter prices
Peoples Gas		Uses computer models to optimize for the lowest-cost gas supply over the full season.
Ameren Illinois	Target full storage at November 15th. Injection and withdrawal schedules are developed to operate storage facilities for reliability to protect the storage reservoir integrity at the lowest cost.	Winter usage favors pipeline capacity, then no- notice storage withdrawals from contracted storage, then balance remaining demand from on-system storage.
Nicor Illinois	Uses historical aquifer performance and operational experience for target inventory levels and aquifer pressures necessary to meet peak, seasonal, and daily needs. Injections as required.	Maximize access to available pipeline deliveries
MidAmerican Energy	Vatory Proposition and Company Sources	

Sources: ICF, LDC Regulatory Proceeding and Company Sources



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Attachment

4. Implications of Changes in Natural Gas Markets on Page 21 of 64 **Storage Value**

ICF is forecasting significant changes in the value of natural gas storage over the next five years. The rapid expansion of natural gas production, particularly from the Marcellus and Utica shales, has helped suppress natural gas prices over the past five years. This has led to generally declining natural gas prices, lower seasonal value of natural gas, lower natural gas price volatility, which has generally held down the value of natural gas storage during this period.

However, gas markets are in a period of transition away from the over-supplied gas market of the past several years. Supply growth is expected to lag demand and natural gas prices are expected to begin to increase. The shift in the natural gas markets is expected to lead to a higher seasonal value of natural gas, and higher gas price volatility, leading to an increase in the value of natural gas storage.

This section of the report reviews the changes in natural gas market conditions that ICF expects to impact the natural gas markets and the value of gas storage for Enbridge. The first section presents an overview of ICF's North American natural gas market outlook. The second section is focused on the Canadian gas market, examining the potential shifts in inter-regional pipeline flows and natural gas prices. The third section looks at the impact of weather on natural gas storage scenarios and how ICF constructed its weather cases that Enbridge used to evaluate various gas storage options.6

4.1 North America Gas Market Outlook

4.1.1 North American Demand Outlook

The rapid growth of Marcellus/Utica production encourages continued growth in gas consumption and exports from North America. Through 2020, growth in North America demand is primarily export driven, and the majority of the expected exports are via LNG terminals and piped gas to Mexico. Natural Gas demand trends in Canada are expected to closely follow the rest of North America.

The power generation sector has been the major driver of incremental gas consumption within North America. The growth in power sector gas consumption is driven by multiple factors, including the favorable economics of gas-fired generation, pre-existing environmental regulation (such as Mercury and Air Toxic Standards), and – for now – the Clean Power Plan (CPP) which encourage the retirement of coal plants.

⁶ The outlook and forecasts discussed in this section are those of ICF and may differ from views of Enbridge in some respects.



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Gas demand is also expected to grow in other sectors, but at a more modest pace. Industrial Page 22 of 64 demand is projected to increase by about 10 percent through 2025, primarily due to increases in petrochemicals industries which are concentrated on the U.S. Gulf Coast. Residential and commercial gas demands are expected to rise only slightly, as increased demand due to the addition of new gas customers is partially offset by reductions in per-customer consumption due to energy efficiency improvements.

ICF's base case model includes carbon price assumptions reflecting known and anticipated North American carbon policy. Most of the impact from carbon policies on natural gas demand will occur post-2025.

Gas demand in Mexico is expected to increase sharply in order to meet growing power generation gas demand in Mexico. By 2025, ICF projects that pipeline export to Mexico will reach 6 Bcfd, more than double the 2014 export volumes.

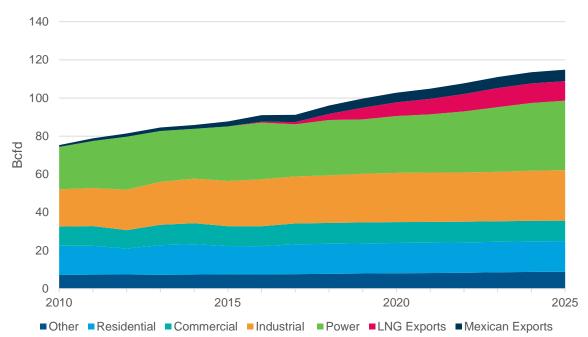


Exhibit 4-1: U.S. and Canada Natural Gas Demand by Sector

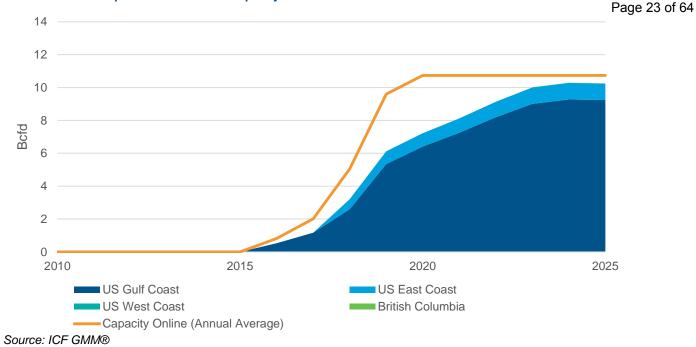
Source: ICF GMM®

Since 2012, the U.S. Department of Energy (DOE) has approved applications for LNG exports from nine U.S. LNG terminals; the majority of these facilities are planned for the Gulf Coast, and one terminal (Cheniere's Sabine Pass) has already started exporting volumes. In Canada, the National Energy Board (NEB) has approved ten proposals for export terminals located on the British Columbia coast. ICF's current projection assumes total North American LNG exports reach 10.2 Bcfd by 2025, with the majority (9.2 Bcfd) coming from the U.S. Gulf Coast.



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Exhibit 4-2: LNG Export Volume versus Capacity



4.1.2 North American Supply Outlook

With the advent of new shale gas supplies, the North American natural gas market has changed dramatically in the past ten years. Prior to the rise of shale gas, U.S. consumption was increasing more quickly than production, and as a result gas prices were relatively high and volatile. As gas prices increased, investments were made in new technologies to develop the vast natural gas reserves found in shale formations.

While it had been long known that there were large deposits of gas and oil in shale formations, it was not until the early 2000s that techniques were developed to economically tap these reserves. The new combination of directional drilling and hydraulic fracturing techniques were first applied in the Barnett Shale in north Texas, but quickly spread to other regions. The first successful shale well in the Marcellus Shale (which stretches from West Virginia through Northeastern Pennsylvania) was drilled in 2004, but Marcellus production did not reach significant levels until 2010. Shale gas development has also spread to the Utica Shale, an over-lapping play that extends into eastern Ohio. Since 2004, over 13,000 wells have been drilled in the Marcellus and Utica shale.

Total U.S. and Canadian gas production is currently about 92 Bcfd, with the Marcellus/Utica accounting for over 20 percent of total North American production. Production growth has been centered in the Marcellus/Utica due to the size of the resource (estimated to be well over 1,000 trillion cubic feet) and low per-unit production costs. Recent declines in oil and gas prices have resulted in a slow-down in drilling rig activity across North America, including in the Marcellus/Utica area. Between November of 2015 and November of 2016, the number of active

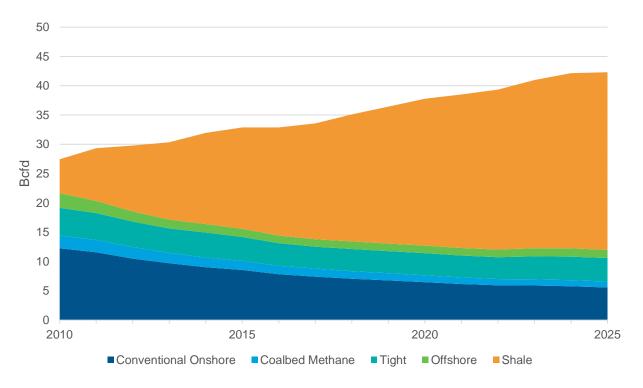


growth from 2015 through 2025.

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drilling rigs in the Marcellus and Utica plays declined by 22 percent. Despite the decline in rig Attachment activity, Marcellus/Utica production has continued to increase due to improvements in well productivity (i.e. more gas produced per well drilled). ICF projects Marcellus/Utica production will reach about 31 percent of total North American production by 2025. While other shale plays are also increasing, Marcellus/Utica accounts for a large majority of the projected production

Exhibit 4-3: U.S. and Canada Natural Gas Production



Source: ICF GMM®

The shifts in regional gas supply and demand have changed interregional pipeline flow patterns, and the changes are likely to continue in the future. Marcellus/Utica production growth has already resulted in dramatic changes to pipeline flow patterns, with the Northeast becoming a net exporting region. Prior to the development of Marcellus and Utica, the Mid-Atlantic and Northeast U.S. relied on gas supplies from the Gulf Coast and Western Canada.

As Marcellus/Utica production continues to grow and becomes an even larger source of gas supplies to other areas, flows along the traditional in-bound paths are increasingly reversed as gas flows out of the region to the South, to the Midwest, and to Eastern Canada.

Flows from Western Canada to the east remain low, as consumers in Eastern Canada increasingly rely on Marcellus/Utica supplies. Flows out of Western Canada are also limited by

⁷ "Rig Count Overview & Summary Count". Baker Hughes. November 18, 2016.



Exhibit 1.D1.EGDI.STAFF.10

increased gas demand within the region to support LNG exports from British Columbia and oil Attachment sands development in Alberta.

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Impact of Flow Changes to Enbridge

In recent years Enbridge has undertaken a review of the gas supply sources used as part of the company's gas supply planning, letting select pipeline contracts expire and taking out new pipeline contracts to access low-cost gas sources. The changes taking place across North America in natural gas supply and demand will have fundamental impact on the price relationships between the available sources of natural gas for Enbridge. For instance;

- The rapid growth in Marcellus/Utica supply is turning the Northeastern U.S. into a major supply center, pushing down prices at major Northeast hubs, including Dominion South Point. Dominion South Point is the most liquid hub in the Marcellus/Utica area, and is used as a proxy for Marcellus/Utica prices.
- The concentration of demand growth along the Gulf Coast (from LNG exports, Mexican exports, and industrial demand) is changing the Gulf Coast into a net demand region.
 Prices at Henry Hub are expected to increase relative to Dominion South Point, which attracts gas from Marcellus/Utica to flow southward.
- In Western Canada, the decline in conventional natural gas production, combined with growth in natural gas demand for oil sands production and LNG exports is expected to lead to higher prices at AECO relative to Marcellus/Utica.

These changes in price relationships increase the attractiveness of natural gas supply purchased from the Marcellus/Utica area for consumers throughout the Northeastern U.S, the Midwest and Central Canada, relative to the supply basins that these regions have historically relied upon.

A major determinant of the production outlook for the Marcellus and Utica is the availability of gas pipeline infrastructure to export gas out of the region. In the last three years over 40 distinct projects have been proposed to expand capacity out of the Marcellus/Utica. Appendix C includes ICF's assumptions of the planned pipeline capacity additions near Ontario by their primary destination markets.

As these facilities are constructed and Marcellus and Utica production gains better access to the broader gas market, gas prices in the Marcellus/Utica area would be expected to increase, relative to Henry Hub. Basis spreads between Marcellus/Utica and other markets will better reflect the cost of pipeline transportation than the effects of constraints in takeaway capacity as is now the case.

⁸ Enbridge's 2017 Rate Application (EB-2016-0215) states, "changes to the TransCanada Pipelines Limited ("TCPL") Mainline toll structure and increasing supply opportunities in the United States northeast have influenced a shift from Alberta purchases (paired with long haul transportation) to Ontario purchases at the Dawn and Niagara receipt points (paired with short haul transportation)."



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4.1.3 North American Price Outlook

ICF expects natural gas prices across North America to increase in the coming years as producers continue to reduce capex and gas demand increases. Low gas production costs will prevent large price increases from occurring, as a supply response is expected due to increasing gas prices that make it economic to grow gas production in areas outside of the Marcellus and Utica shale. For instance, gas prices ranging from US\$4.00 to US\$5.00 per MMBtu are sufficient to foster strong supply development in areas outside of the Marcellus and Utica shales.

ICF's forecast is for Henry Hub natural gas prices to stay below US\$4.00 per MMBtu through 2020 and longer-term prices are expected to range between US\$4.00 and US\$5.00 per MMBtu. ICF projects that prices at Dawn will rise above US\$4.00/MMBtu (in 2015 US\$) by 2022 and range between US\$4.00 and US\$4.50/MMBtu (in 2015\$) through 2025.

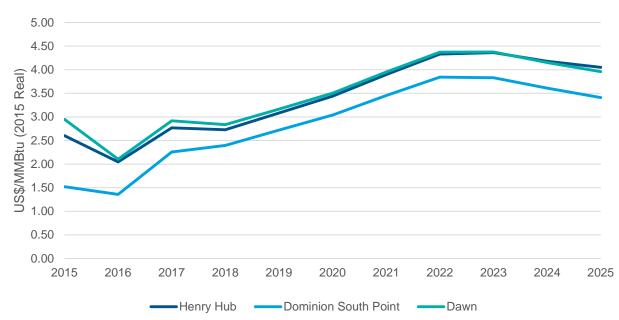


Exhibit 4-4: Natural Gas Prices (US\$) at Henry Hub, Dominion South Point, and Dawn

Source: ICF GMM®

As new natural gas pipeline capacity from Marcellus/Utica is added, basis between Dawn and Dominion South Point will decline to US\$0.50-US\$0.60/MMBtu (in 2015 US\$). Furthermore, as Dawn receives a greater portion of its gas supplies from the Marcellus/Utica, Dawn's basis to Henry Hub will continue to narrow and by 2025 prices at Dawn are projected to trade at a slight discount to Henry Hub.



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4.2 Ontario Natural Gas Market Outlook

4.2.1 Supply and Demand Trends

Ontario's natural gas demand in 2015 was about 2.6 Bcfd and accounted for approximately 26 percent of Canada's total natural gas demand. The demand in Ontario is expected to increase slightly to 2.7 Bcfd in 2016. ICF projects Ontario's natural gas demand to increase to 3.6 Bcfd by 2025.

Currently, the residential sector, which mainly relies on natural gas for space and water heating, has the largest demand for natural gas in Ontario and averages about 0.9 Bcfd annually. The residential and power generation sectors together comprise over half of Ontario's natural gas demand. ICF expects power generation gas demand to experience the most growth during the next decade, increasing from 0.5 Bcfd in 2016 to 0.9 Bcfd in 2025. As nuclear power plants retire and access to gas from the Marcellus/Utica supply region of the U.S. improves, natural gas-fired power generation is projected to increase significantly.

4.0 3.5 3.0 2.5 Bcfd 2.0 1.5 1.0 0.5 0.0 2015 2020 2010 2025 Other Residential Commercial Industrial ■ Power Generation

Exhibit 4-5: Ontario Natural Gas Demand

Source: ICF GMM® Case

ICF's base case model includes a carbon price assumptions reflecting Ontario's Cap & Trade program. ⁹ The expected impacts of this program and related initiatives to reduce Green House Gas (GHG) emissions on future natural gas demand in Ontario are evolving as Ontario policy

⁹ The Government of Ontario passed legislation establishing a Cap and Trade Program in an effort to reduce Greenhouse Gas ("GHG") emissions. This program is set to commence in January 2017.



Exhibit 1.D1.EGDI.STAFF.10

continues to be developed and implemented. Much of the impact will effect natural gas demand Attachment levels post-2025. 10 Page 28 of 64

4.2.2 Regional Supply Trends

Ontario has little natural gas production of its own, and thus imports practically all of its supply from other regions in Canada and the United States. Ontario receives its natural gas from three main flow pathways, from Michigan, Western Canada and Niagara, with minimal volumes from Iroquois. In 2015, the largest regional supplier of natural gas to Ontario was Western Canada, which supplied 2.0 Bcfd on an average annual basis.

ICF projects that flows from Western Canada into Ontario will decline in the medium-term and begin to grow slowly starting in 2020, reaching 1.4 Bcfd by 2025. There will be another noteworthy increase in flows from Western Canada after 2031 as power sector gas demand increases mainly due to nuclear retirements.

The second biggest source of natural gas for Ontario is Michigan, which in turn sources its gas from the Midcontinent, Rockies, and increasingly the Marcellus/Utica supply region. In 2015, 1.5 Bcfd flowed from Michigan into Ontario. The supply from Michigan is projected to reach 2.4 Bcfd in 2018 and will remain relatively stable near 2.2 Bcfd until 2025.

In recent years Marcellus/Utica gas has also been flowing northbound on the Tennessee and National Fuel pipeline systems to supply Ontario via the border crossing at Niagara, New York. By 2025 Ontario will receive 33 percent of its supplies from Western Canada, 47 percent via Michigan, and 20 percent via Niagara. ICF does not anticipate development of the TransCanada South-to-North (SONO) Pipeline due to concerns about the economic viability of the project as well as concerns about ongoing environmental opposition to pipeline development in New York, including completion of the Constitution Pipeline. As a result, ICF's forecast does not include physical pipeline flows from New York into Ontario via the Iroquois Pipeline.

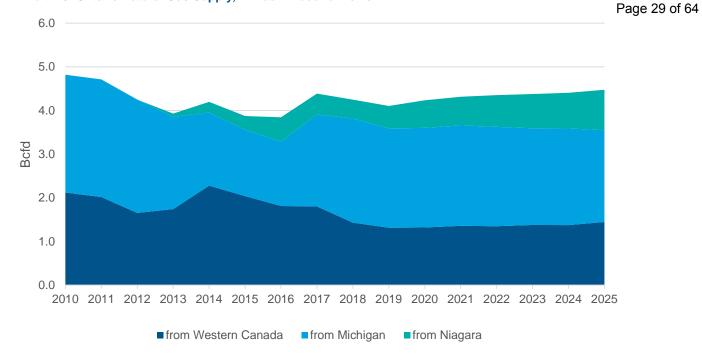
¹¹ See Appendix C for pipeline build assumptions included in ICF Base Case.



¹⁰ ICF's forecast includes several related carbon reduction initiatives (Renewable Natural Gas, Energy Efficiency, Liquid Natural Gas/Compressed Natural Gas, Combined Heat and Power) that are expected to reduce emissions by 10-12 Mt CO2e, refined fuel initiatives reduce emissions by 5-8 Mt CO2e, and a reduction of 3-5 Mt CO2e due to increasing fuel prices.

Filed: 2017-11-13 EB-2017-0086 Exhibit 1.D1.EGDI.STAFF.10 Attachment

Exhibit 4-6: Ontario Natural Gas Supply, Annual In-bound Flows



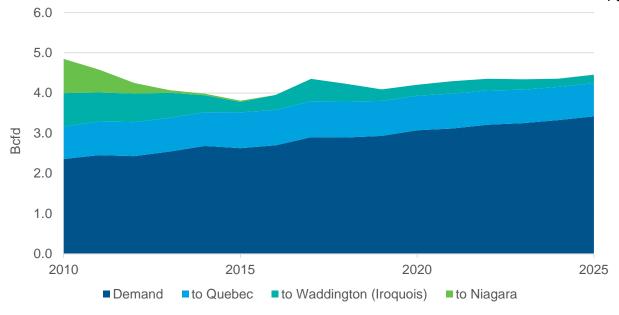
Source: ICF GMM® Case

Another important factor that will influence pipeline flows in Ontario will be the growth in New York and New England peak winter demand. That demand growth is expected to be greater than the planned pipeline capacity additions from the Appalachian Basin directed toward that region. Flows from Ontario and Québec into the Northeastern U.S. will remain a critical component of peak period supply in the U.S. Northeast. Flows into Québec/Waddington are expected to peak in 2017 at 1.45 Bcfd, and decline through 2025.



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Exhibit 4-7: Annual Ontario Demand and Out-bound Flows

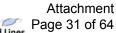


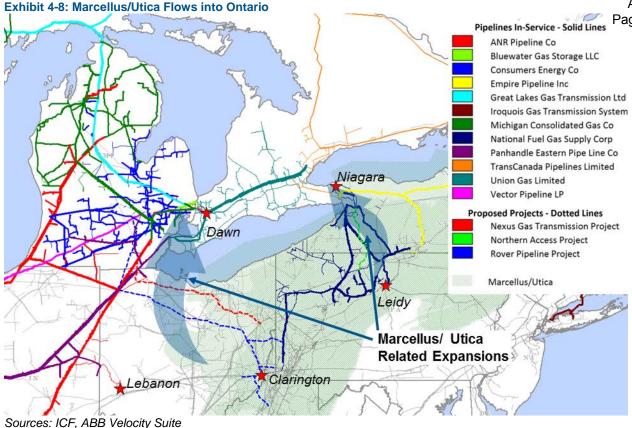
Source: ICF GMM®

Over the past 3 years, capacity expansions by Tennessee, Dominion, National Fuel, and Empire have made it easier to move Marcellus gas to Niagara and Parkway. Out of Michigan, there is approximately 789 MMcfd of contracted capacity in Ontario on the Great Lakes pipeline, 167 MMcfd of capacity on Panhandle Eastern, and 1,081 MMcfd on the Vector pipeline. If completed, new pipelines proposed by Spectra Energy and DTE Energy (NEXUS) and Energy Transfer Partners (Rover) would allow additional Marcellus and Utica production to move to Dawn. Capacity expansions within Ontario will also allow greater access to Marcellus/Utica supplies.



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Countering increased flows from the Marcellus/Utica region, ICF anticipates decreased flows from Western Canada due to TransCanada's Energy East pipeline project, which is included in ICF's base case pipeline assumptions. If approved, TCPL's Energy East project would remove about 1.2 Bcfd of capacity from service on the Mainline from Alberta to eastern Ontario. In conjunction with the Energy East project, TCPL also proposes to add some new capacity in eastern Ontario (Eastern Mainline Expansion), though net capacity into Ontario would be below what is currently available. This could put a strain on the supply infrastructure in Ontario since during two of the last three winters, all of the current capacity was used on peak winter days.

ICF's Pipeline Buildout Assumptions are included in Appendix C.

4.3 Implications to Ontario Storage Values

The North American gas markets are in a period of transition, going from being over-supplied and possessing low seasonal gas spreads to a market that is expected to be driven by rapidly growing gas demand and more volatility. As the market shifts, the seasonal value of natural gas, which is highly related to natural gas price trends, is expected to recover sharply over prior year levels.

In a declining price environment the difference between summer and winter prices is narrower than what it would be in flat or rising price scenario. Indeed, the declining price trends of the

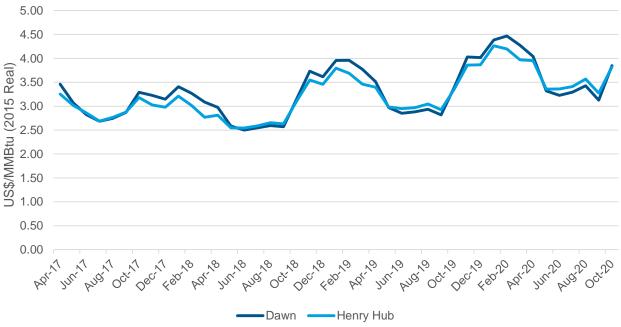


Exhibit 1.D1.EGDI.STAFF.10

past several years has resulted in low values of seasonal natural gas in storage as the annual Attachment Henry Hub price declined by an average of \$0.40 per MMBtu per year since 2010.

ICF's July 2016 Base Case natural gas price forecasts for Henry Hub and Dawn used in this analysis are shown in Exhibit 4-9 below.

Exhibit 4-9: ICF's April 2016 Base Case Monthly Gas Price (US\$) Forecast for Henry Hub and Dawn



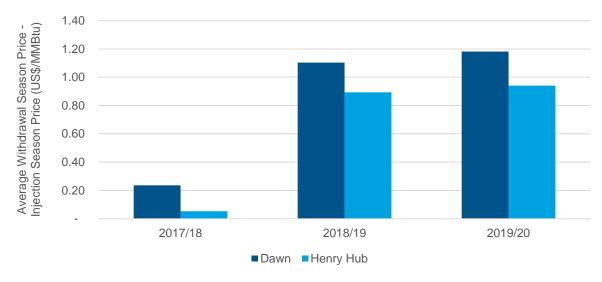
Source: ICF Gas Market Model

ICF expects that rising natural gas prices will be supportive of seasonal price differentials over the next few years. In 2018/19, the seasonal value of gas at Dawn is expected to be \$1.10 per MMBtu, rising to \$1.18 per MMBtu in 2019/20. Due to higher seasonality in prices, the seasonal value of gas at Dawn is also expected to average \$0.21 per MMBtu higher than the seasonal value of gas at Henry Hub.



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Exhibit 4-10: Seasonal Gas Price (US\$) Spread for Dawn and Henry Hub



Sources: ICF GMM® Case

In addition to an increase in seasonal values of natural gas, ICF also expects that the tighter gas market will exhibit increased gas price volatility, which can further increases the value of holding natural gas storage.



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5. Value of Incremental Storage to Enbridge Gas

5.1 Approach

ICF has used the analysis of North American and Ontario natural gas markets, combined with the assessment conducted by Enbridge on the company's gas supply portfolio costs, to assess the impact of changes in natural gas storage capacity held by the company on the utility's overall gas supply portfolio cost.

The analysis was conducted in three steps:

- ICF developed a series of alternative natural gas market scenarios reflecting differences in weather corresponding to Enbridge planning scenarios for Budgeted Weather, Colder than Budgeted Weather, and Warmer than Normal Weather.
- 2) ICF specified a series of alternative storage capacity and cost scenarios, and Enbridge used the Enbridge SENDOUT© model to evaluate total supply portfolio costs for each weather scenario, storage capacity scenario, and storage cost scenario.
- ICF used the results of the Enbridge SENDOUT© analysis of supply portfolio costs to evaluate the impact of changes in natural gas storage capacity on Enbridge supply portfolio costs.

Each of these steps is described in more detail below.

5.1.1 Alternative Weather Scenarios

ICF used its April 2016 Gas Market Model (GMM) Base Case as the starting basis for its evaluation of the North American natural gas markets and Enbridge's gas storage operations. The GMM is an internationally recognized model of the North American gas market that includes projections for natural gas demand by sector, conventional and unconventional natural gas resources, production costs, and other major gas market developments, such as potential Liquefied Natural Gas (LNG) exports. The GMM projects monthly natural gas demand, supply, and prices for more than 120 regions and is a general equilibrium market model. The model is described in more detail in Appendix D. ICF used the GMM to conduct sophisticated analysis of the potential impacts and risks associated with alternative weather scenarios on natural gas demand and prices.

ICF used the GMM to develop three alternative price scenarios reflecting Enbridge's planning scenarios for Budgeted Weather, Colder than Budgeted Weather, and Warmer than Budgeted Weather.

This analysis is used to determine the value of storage capacity during a variety of weather conditions, such as the weather observed during the winter of 2013/14, which drove citygate prices outside of the producing regions to extremely high levels. Each weather scenario is based on the 3-year time period from April 2017 through March 2020.

For each weather scenario, Enbridge's daily load profile includes the company's peak day design criteria, which includes 18 separate peak days that are designed to mimic the coldest



Exhibit 1.D1.EGDI.STAFF.10

temperatures expected over the winter season. ¹² Enbridge's Peak Design Day is based on a 1 Attachment in 5 recurrence interval derived from a lognormal distribution of Heating Degree Days (HDDs). Attachment Page 35 of 64

In order to evaluate the impact of colder than normal and warmer than normal weather on market demand and prices, ICF ran 85 cases of actual 3-year weather patterns in the GMM to assess the potential impact of weather on demand and prices in order to project demand and gas prices.

The use of actual weather scenarios is important for assessing the actual range of impacts due to the range of positive and negative correlations between weather patterns in different regions of North America. This weather sensitivity analysis forms the basis needed to evaluate the company's gas storage operations and the impact of weather volatility on natural gas prices and basis at the natural gas market centers considered important by Enbridge.

The three Enbridge weather scenarios (Colder, Budgeted, and Warmer) were constructed to best approximate Enbridge's HDD forecast for each of its weather planning scenarios. Each of these three weather scenarios were crafted from an average of four unique weather cases selected from the larger set of 85 weather cases. These four weather cases for each scenario were selected to develop a composite scenario that most closely aligned with Enbridge's three planning scenarios.

Enbridge's Budgeted Weather scenario assumptions are determined by the company's Economics and Business performance department, which utilizes an OEB approved methodology to determine the level of HDDs to be used in gas supply planning. For the purpose of this analysis, Enbridge then developed a Colder than Budgeted and Warmer than Budgeted weather scenario. The Colder than Budgeted weather scenario reflects a winter with daily average weather 10 HDDs colder than the Budgeted weather scenario. The Warmer than Budgeted scenario reflects a winter with daily average weather 10 HDDs warmer than the budgeted weather conditions. The three weather scenarios are summarized below:

- The Colder than Budgeted Weather Scenario had a target of 3,373 HDDs at Toronto. ICF selected the three year weather period starting in 1933 (3,368 HDDs), 1942 (3,335 HDDs), 1969 (3,403 HDDs), and 1977 (3,403 HDDs) to construct the aggregated Cold Weather Case. These four ICF weather cases had an average of 3,377 HDDs.
- The Budgeted Weather Scenario had a target of 2,835 HDDs at Toronto. ICF selected the three year weather period starting in 1936 (2,822 HDDs), 1948 (2,824 HDDs), 1953 (2,911 HDDs), and 1992 (2,825 HDDs) to construct the aggregated Budget Weather Case. These four ICF weather cases had an average of 2,846 HDDs.
- The Warmer than Budgeted Weather Scenario had a target of 2,665 HDDs at Toronto. ICF selected the three year weather period starting in 1952 (2,706 HDDs), 1997 (2,682

¹² Enbridge Gas Distribution 2017 Rate Case Application EB-2016-0215, Exhibit D1

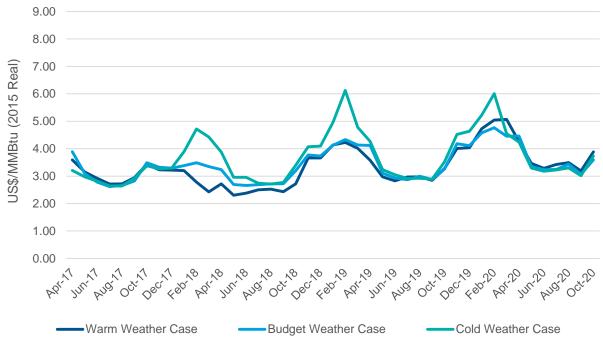


Exhibit 1.D1.EGDI.STAFF.10

HDDs), 1999 (2,717 HDDs), and 2015¹³ (2,510 HDDs) to construct the aggregated Warm Weather Case. These four ICF weather cases had an average of 2,654 HDDs.

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Exhibit 5-1: Dawn Prices (US\$) Under the Three Enbridge Weather Scenarios



Source: ICF Gas Market Model

5.1.2 Alternative Storage Scenarios

The resulting commodity price and demand outlooks across the Colder than Budgeted, Budgeted, and Warmer than Budgeted weather cases were provided to Enbridge by ICF and then used by Enbridge to assess the impact of alternative storage scenarios on Enbridge natural gas supply portfolio costs using the Enbridge SENDOUT© model.

The SENDOUT© analysis was conducted for five different levels of storage capacity specified by ICF:

- 1) Base Case storage capacity: 114 Bcf
- 2) Base Case Storage Capacity plus 5 Bcf
- 3) Base Case Storage Capacity plus 10 Bcf
- 4) Base Case Storage Capacity plus 15 Bcf
- 5) Base Case Storage Capacity plus 20 Bcf

The Base Case capacity includes Enbridge gas storage capacity, plus capacity currently contracted from third party storage providers. For each alternative storage scenario ran in

¹³ The 2015 weather case uses a 20 year weather average (1991-2010) for the second and third year of weather data.



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SENDOUT©, Enbridge added five Bcf of incremental storage capacity. For the purposes of this Attachment analysis, Enbridge assumed that the gas storage would be available at or near Dawn. ¹⁴ Page 37 of 64

5.1.3 Incremental Storage Costs

The cost of the incremental storage capacity added to the Base Case storage levels were based on currently estimated costs of contracting gas storage capacity from nearby storage providers. Given the potential volume of incremental storage capacity, these costs were considered to represent a floor, or minimum cost, on prices for incremental storage capacity.

In order to evaluate the impact of a significant increase in storage costs, Enbridge also replicated the analysis with storage costs 50 percent above the Base Case storage costs. The storage cost estimate of 50 percent above the Base Case costs was chosen as a reasonable High Storage Cost scenario based on an assessment of the potential impact of changes in natural gas markets on the seasonal value of natural gas held in storage.

For each additional five Bcf of storage capacity, Enbridge included a one percent increase in the capacity costs from the Base and High Storage Cost capacity estimates in the SENDOUT© Model scenario, reflecting a modest impact of the increase in demand for storage capacity on storage costs.

The costs of incremental storage for the Base Case and High Storage Cost Case are shown in Exhibit 5-2.

Exhibit 5-2: Incremental Storage Costs Used in Enbridge SENDOUT® Modeling

	Base Case	High Storage Cost Case
Capacity Cost (\$/10^3 M3/Month)	CAD\$2.99 ¹⁵	CAD\$4.48
Rate - Injection (\$/10^3 M3)	CAD\$0.23	CAD\$0.23
Rate - Withdrawal (\$/10^3 M3)	CAD\$0.23	CAD\$0.23
Fuel - Injection (%)	0.60%	0.60%
Fuel - Withdrawal (%)	0.60%	0.60%
Carrying Cost (% per Year)	7.81%	7.81%

5.1.4 Pipeline Capacity and Capacity Costs

The Enbridge SENDOUT© Model results and corresponding analysis were based on the Company's currently projected natural gas pipeline portfolio.¹⁶ No adjustments were made to Enbridge's pipeline contract portfolio, gas storage targets, or spot gas purchasing guidelines to

¹⁶ Portfolio assumptions correspond to Enbridge's contracts in place as of the time of analysis for the forecast period of April 2017 to October 2020, which align with the portfolio assumptions underpinning the 2017 Rate Application (EB-2016-0215).



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¹⁴ For the SENDOUT© analysis, Enbridge has assumed that new storage is available at or near Dawn and does not require incremental pipeline capacity. Hence, the Enbridge SENDOUT© Model analysis does not include any changes to the upstream transportation portfolio, resulting in fixed transportation costs across all scenarios.

¹⁵ A 1 percent increase in storage capacity costs was added for each additional 5 Bcf tranche of storage capacity.

Exhibit 1.D1.EGDI.STAFF.10

reflect the change in gas storage capacity and peak period storage deliverability. Gas supply purchases reflect the lowest cost source of natural gas supply consistent with the availability of contracted pipeline capacity and gas storage operational targets. Generally, the changes in gas supply purchases due to the changes in storage capacity and deliverability are reflected in changes in natural gas purchases at Dawn, rather than changes in pipeline deliveries.

5.2 Projected Impact of Incremental Storage Capacity on Enbridge Gas Supply Portfolio Costs

ICF evaluated the results of Enbridge's SENDOUT© Model runs to determine the value of incremental natural gas storage capacity for each of the five levels of contracted storage capacity for each of the three weather scenarios, using two different storage cost scenarios.

5.2.1 Reference Storage Costs

The results of the SENDOUT© analysis for each Weather scenario that are based on the assumption that storage costs would remain consistent with costs currently available in the market are shown in Exhibit 5-3¹⁷. Exhibit 5-4 illustrates the impact of the increase in storage capacity on Enbridge supply portfolio costs for these scenarios.

5.2.2 50 Percent Higher Storage Costs

The results of the SENDOUT© analysis for each Weather scenario that are based on the assumption that storage capacity costs will increase by 50 percent from current costs are shown in Exhibit 5-5, with an additional 1 percent increase in storage capacity costs for each storage increment of 5 Bcf. The storage cost estimate of 50 percent above the Base Case costs was chosen as a reasonable High Storage Cost scenario based on an assessment of the potential impact of changes in natural gas markets on the seasonal value of natural gas held in storage.

Exhibit 5-6 illustrates the impact of the increase in storage capacity on Enbridge supply portfolio costs for these scenarios.

5.2.3 Summary

In all of the scenarios, the increase in storage capacity allows Enbridge to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher.

¹⁷ Storage costs include an additional 1 percent increase in storage capacity costs for each additional storage increment of 5 Bcf.



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Exhibit 5-3: Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs:

Current Storage Capacity Costs (Million CAD\$)

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Average Annual Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 Reference Storage Costs					
(CAD\$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	ge Costs Warmer than Budgeted Weather Scenario	Change from Budgeted (Colder)	Change from Budgeted (Warmer)
Total Supply Portfolio Cost	ts				
Existing Storage Capacity	2,152.0	1,800.5	1,686.6	351.5	-113.9
Plus 5 Bcf	2,139.8	1,797.3	1,683.7	342.4	-113.6
Plus 10 Bcf	2,127.6	1,794.4	1,681.0	333.2	-113.3
Plus 15 Bcf	2,115.4	1,791.5	1,678.5	323.9	-113.0
Plus 20 Bcf	2,104.4	1,788.8	1,678.6	315.6	-110.2
Gas Supply Costs					
Existing Storage Capacity	1,610.6	1,258.9	1,144.8	351.7	-114.1
Plus 5 Bcf	1,592.6	1,250.0	1,136.1	342.6	-113.9
Plus 10 Bcf	1,574.5	1,241.3	1,127.6	333.2	-113.7
Plus 15 Bcf	1,556.3	1,232.6	1,119.2	323.7	-113.4
Plus 20 Bcf	1,539.4	1,223.9	1,113.3	315.4	-110.7
Storage Costs					
Existing Storage Capacity	27.9	28.1	28.3	-0.2	0.2
Plus 5 Bcf	33.7	33.8	34.1	-0.1	0.3
Plus 10 Bcf	39.6	39.6	40.0	0.0	0.3
Plus 15 Bcf	45.5	45.4	45.9	0.1	0.5
Plus 20 Bcf	51.5	51.4	51.8	0.2	0.4
Transport Costs					
Existing Storage Capacity	513.5	513.5	513.5	0.0	0.0
Plus 5 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 10 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 15 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 20 Bcf	513.5	513.5	513.5	0.0	0.0



Exhibit 1.D1.EGDI.STAFF.10

Exhibit 5-4: Average Annual Change in Enbridge Supply Portfolio Costs From Incremental Storage Capacity: Attachment Current Storage Capacity Costs (Million CAD\$)

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Average Annual Impact of Incremental Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 Reference Storage Costs					
(CAD\$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario		
Total Supply Portfolio Costs					
Existing Storage Capacity	2,152.0	1,800.5	1,686.6		
Plus 5 Bcf	-12.3	-3.2	-2.9		
Plus 10 Bcf	-24.4	-6.1	-5.5		
Plus 15 Bcf	-36.7	-9.0	-8.0		
Plus 20 Bcf	-47.6	-11.7	-8.0		
Gas Supply Costs					
Existing Storage Capacity	1,610.6	1,258.9	1,144.8		
Plus 5 Bcf	-18.1	-8.9	-8.7		
Plus 10 Bcf	-36.1	-17.6	-17.2		
Plus 15 Bcf	-54.3	-26.3	-25.6		
Plus 20 Bcf	-71.3	-35.0	-31.5		
Storage Costs					
Existing Storage Capacity	27.9	28.1	28.3		
Plus 5 Bcf	5.8	5.7	5.8		
Plus 10 Bcf	11.7	11.5	11.6		
Plus 15 Bcf	17.6	17.3	17.6		
Plus 20 Bcf	23.6	23.3	23.5		
Transport Costs					
Existing Storage Capacity	513.5	513.5	513.5		
Plus 5 Bcf	0.0	0.0	0.0		
Plus 10 Bcf	0.0	0.0	0.0		
Plus 15 Bcf	0.0	0.0	0.0		
Plus 20 Bcf	0.0	0.0	0.0		



Exhibit 1.D1.EGDI.STAFF.10

Exhibit 5-5: Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs: 50 Attachment Percent Higher Storage Capacity Costs (Million CAD\$) Page 41 of 64

Average Annual Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 50 Percent Higher Storage Costs					
(CAD\$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario	Change from Budgeted (Colder)	Change from Budgeted (Warmer)
Total Supply Portfolio Cost	S				
Existing Storage Capacity	2,152.0	1,800.5	1,686.6	351.5	-113.9
Plus 5 Bcf	2,142.3	1,799.9	1,686.3	342.4	-113.6
Plus 10 Bcf	2,132.7	1,799.5	1,686.1	333.2	-113.3
Plus 15 Bcf	2,123.1	1,799.2	1,686.2	323.9	-113.0
Plus 20 Bcf	2,114.7	1,799.1	1,688.9	315.6	-110.2
Gas Supply Costs					
Existing Storage Capacity	1,610.6	1,258.9	1,144.8	351.7	-114.1
Plus 5 Bcf	1,592.6	1,250.0	1,136.1	342.6	-113.9
Plus 10 Bcf	1,574.5	1,241.3	1,127.6	333.2	-113.7
Plus 15 Bcf	1,556.3	1,232.6	1,119.2	323.7	-113.4
Plus 20 Bcf	1,539.4	1,223.9	1,113.3	315.4	-110.7
Storage Costs					
Existing Storage Capacity	27.7	28.1	28.3	-0.4	0.2
Plus 5 Bcf	36.2	36.4	36.6	-0.1	0.3
Plus 10 Bcf	44.7	44.7	45.1	0.0	0.3
Plus 15 Bcf	53.2	53.1	53.6	0.1	0.5
Plus 20 Bcf	61.8	61.7	62.1	0.2	0.4
Transport Costs					
Existing Storage Capacity	513.5	513.5	513.5	0.0	0.0
Plus 5 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 10 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 15 Bcf	513.5	513.5	513.5	0.0	0.0
Plus 20 Bcf	513.5	513.5	513.5	0.0	0.0



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Exhibit 5-6: Average Annual Change in Enbridge Supply Portfolio Costs Due To Incremental Storage
Capacity: 50 Percent Higher Storage Capacity Costs (Million CAD\$)

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Average Annual Impact of Incremental Supply Portfolio Costs by Case for the Three Year Period from April 2017 to March 2020 50 Percent Higher Storage Costs						
(CAD\$Millions)	Colder than Budgeted Weather Scenario	Budgeted Weather Scenario	Warmer than Budgeted Weather Scenario			
Total Supply Portfolio Costs	•					
Existing Storage Capacity	2,152.0	1,800.5	1,686.6			
Plus 5 Bcf	-9.7	-0.6	-0.3			
Plus 10 Bcf	-19.3	-1.0	-0.4			
Plus 15 Bcf	-29.0	-1.3	-0.4			
Plus 20 Bcf	-37.3	-1.4	2.3			
Gas Supply Costs						
Existing Storage Capacity	1,610.6	1,258.9	1,144.8			
Plus 5 Bcf	-18.1	-8.9	-8.7			
Plus 10 Bcf	-36.1	-17.6	-17.2			
Plus 15 Bcf	-54.3	-26.3	-25.6			
Plus 20 Bcf	-71.3	-35.0	-31.5			
Storage Costs						
Existing Storage Capacity	27.7	28.1	28.3			
Plus 5 Bcf	8.5	8.3	8.3			
Plus 10 Bcf	16.9	16.6	16.8			
Plus 15 Bcf	25.5	25.0	25.2			
Plus 20 Bcf	34.1	33.6	33.8			
Transport Costs						
Existing Storage Capacity	513.5	513.5	513.5			
Plus 5 Bcf	0.0	0.0	0.0			
Plus 10 Bcf	0.0	0.0	0.0			
Plus 15 Bcf	0.0	0.0	0.0			
Plus 20 Bcf	0.0	0.0	0.0			



increase in storage costs.

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Attachment

Exhibit 1.D1.EGDI.STAFF.10

5.3 Impact of Incremental Storage Capacity on Enbridge Gas

contract during the three year period from April 2017 through March 2020, except for the addition of 20 Bcf of storage capacity in the Warmer that Budgeted scenario with a 50 percent

Page 43 of 64 **Supply Portfolio Costs** Under all of the weather, demand, and the reference storage cost scenarios that ICF evaluated, Enbridge is able to reduce total natural gas portfolio costs by increasing storage capacity under

Under the reference costs total supply portfolio costs are minimized by adding at least 20 Bcf of incremental storage capacity to the Enbridge supply portfolio in both the Colder than Budgeted and Budgeted Weather scenarios, while gas portfolio costs are minimized by adding 15 Bcf of storage capacity in the Warmer than Budgeted Weather scenario.

Under the scenario where storage capacity costs increase by 50 percent relative to existing levels, the Enbridge supply portfolio cost would still be minimized by adding at least 20 Bcf of storage capacity in the Colder than Budgeted scenario and Budgeted Weather scenario. Under the higher storage cost assumptions the Enbridge supply portfolio cost would be minimized by adding up to 15 Bcf of storage capacity.

The overall results of the three year period from April 2017 through March 2020 of all weather, demand, and storage cost scenarios are shown in Exhibit 5-7.

Exhibit 5-7: Average Annual Change in Total Gas Costs from Incremental Storage Capacity From Enbridge SENDOUT© Results (Million CAD\$)

Average Annual Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020						
(CAD\$Millions)	Reference Storage Costs	50 Percent Increase in Storage Costs				
Colder than Budgeted	Weather Scenario					
5 Bcf	-12.3	-9.7				
10 Bcf	-24.4	-19.3				
15 Bcf	-36.7	-29.0				
20 Bcf	-47.6	-37.3				
Budgeted Weather Sc	Budgeted Weather Scenario					
5 Bcf	-3.2	-0.6				
10 Bcf	-6.1	-1.0				
15 Bcf	-9.0	-1.3				
20 Bcf	-11.7	-1.4				
Warmer than Budgeted Weather Scenario						
5 Bcf	-2.9	-0.3				
10 Bcf	-5.5	-0.4				
15 Bcf	-8.0	-0.4				
20 Bcf	-8.0	2.3				



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5.4 Conclusions and Recommendations

Based on the assessment of natural gas market trends, expected natural gas prices at Dawn, and the value of natural gas storage as part of the Enbridge overall supply portfolio, ICF's analysis of Enbridge's SENDOUT© results indicates that additional storage capacity across all scenarios but one would reduce the expected overall cost of the Enbridge gas supply portfolio.

The overall amount of incremental capacity that should be considered by Enbridge will depend on the cost of the incremental storage, and the level of importance Enbridge and its regulator place on minimizing the cost impacts of a colder than normal winter for its customers, relative to minimizing the long-term average cost.

The ICF recommendations are dependent on the cost of incremental storage capacity. If incremental storage costs increase by more than the 50 percent increase relative to existing levels assessed in this analysis, ICF would recommend additional analysis be undertaken to ensure that the benefits of increasing storage capacity will exceed the incremental costs of the storage capacity.

5.4.1 Value of Incremental Storage to Minimize Long-Term Average Costs

A strategy designed to minimize the total long-term cost of the Enbridge supply portfolio to consumers would be heavily weighted toward the Budgeted Weather scenario based on the expected distribution of the weather scenarios given the likelihood of either the Warmer or Colder than budgeted scenarios. Based on a weighting of 60 percent for the Budgeted Weather scenario, and 20 percent for both the Colder than Budgeted and Warmer than Budgeted weather scenarios:

- If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of between and 20 Bcf of incremental storage capacity.
- If incremental storage costs increase by 50 percent relative to existing contracted storage costs, ICF would recommend consideration of about 20 Bcf of incremental storage capacity.

5.4.2 Value of Incremental Storage to Minimize Impacts of Colder than Budgeted Weather

A strategy designed to minimize the potential impact of a colder than normal winter on costs to Enbridge consumers would still weigh the Budgeted scenario most heavily, but would discount the Warmer than Budgeted scenario and over-weight the Colder than Budgeted scenario. The weighting of the different scenarios used to accomplish this objective is a policy judgement that will need to be made by Enbridge. For the purposes of this analysis, ICF has weighted the Colder than Budgeted Weather Scenario at 40 percent, the Budgeted Weather Scenario at 60 percent, and the Warmer than Budgeted Weather Scenario at 0 percent. Under this set of priorities:



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 If the cost of additional storage capacity from third parties remains at or near current storage costs, ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

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 An increase in incremental storage costs of 50 percent relative to existing contracted storage costs would not change the recommendation. ICF would recommend consideration of at least 20 Bcf of incremental storage capacity.

Exhibit 5-8: Average Annual Change in Total Gas Costs from Incremental Storage Capacity, Weighted by Weather Probability (Million CAD\$)

Average Annual Weighted Average Impact of Incremental Storage Capacity on Enbridge Supply Portfolio Costs for the Three Year Period from April 2017 to March 2020					
(CAD\$Millions)	Reference Storage Costs		50 Percent Increase in Storage Costs		
Scenario	Balanced Weighting	Cold Weather Weighting		Balanced Weighting	Cold Weather Weighting
Colder than Budgeted Weather Scenario	20%	40%		20%	40%
Budgeted Weather Scenario	60%	60%		60%	60%
Warmer than Budgeted Weather Scenario	20%	0%		20%	0%
Incremental Storage Capacity					
5 Bcf	-4.9	-6.8		-2.4	-4.3
10 Bcf	-9.7	-13.4		-4.6	-8.3
15 Bcf	-14.3	-20.0		-6.6	-12.4
20 Bcf	-18.2	-26.1		-7.8	-15.8



Exhibit 1.D1.EGDI.STAFF.10

Attachment

Appendix A: Summary Other LDC's Storage Operating Atlactiment Age 46 of 64 **Profile**

A.1.1 Union Gas

Union Gas serves 1.4 million customers across Ontario and operates over 42,250 miles of natural gas transmission and distribution pipelines. The company's customer base is divided into a Northern and Southern region, each of which has different gas supply availability and utilization of the company's gas storage assets.

Union Gas owns and operates the Dawn Storage hub, one of the most liquid natural gas trading hubs in North America. Union Gas' storage operations include 20 gas fields with a working capacity of 152 Bcf and peak deliverability of 2.3 Bcfd. The Dawn Hub has pipeline interconnections with the Vector, Great Lakes, Panhandle, Michcon, and Bluewater transmission pipelines from Michigan in the west, and TransCanada's pipeline and Enbridge's gas distribution system in the east.

Union Gas' Gas Supply plan sets out to optimize the use of the company's contracted upstream pipeline capacity. To achieve this, the company uses a combination of pipeline agreements, gas supplies sourced from the Dawn hub, and storage capacity to fully meet forecasted annual demand. In order to develop its Gas Supply Plan, Union models all upstream transportation capacity and storage assets for integrated service across all areas as part of its 5 year supply plan.

Over the past several years, Union Gas has been de-contracting its most expensive gas supply sources in response to changing gas market conditions. During 2015/16, Union Gas let longhaul capacity contracts with Alliance Vector and TransCanada Pipelines expire. Reductions in pipeline capacity serving Union Gas' Northern areas would be replaced by the expanded backhaul capacity from Dawn to Empress.

To support increased flexibility and use of natural gas sourced from Dawn, Union Gas is undertaking several projects to expand deliverability within its pipeline distribution network. Included in these efforts are two projects, the Dawn to Parkway Expansion, and the contracting of new pipeline capacity with NEXUS pipeline for 149,755 Dth/d, effective November 1, 2017.

Storage usage criteria

Union Gas targets 95 Bcf of gas storage capacity to be used for in-Franchise customers, with 5 Bcf of that capacity available for short-term sales. Union Gas' Dawn gas storage operating criteria to support its winter demand needs includes the following:

- Required storage space is filled on October 31.
- Sufficient inventory at February 28 to meet the design day needs of sales service and bundled DP customers.
- Storage is empty on March 31 (except for 6 Bcf for integrity).

In addition, Union Gas includes the following gas storage capacity agreements:



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- 14.5 Bcf of TCPL Storage Transportation Service and TCPL Dawn Diversions.
 14.2 Bcf of TCPL STS Withdrawals in Winter Months to meet winter demand.
- 14.5 Bcf of Dawn delivered services as part of Union South Supply portfolio, which is 15 percent of the area total.

A.1.2 Gaz Métro

Gaz Métro serves over 195,000 residential customers across Quebec, while also providing natural gas to commercial and industrial users across the province. The company's customer base is heavily weighted toward large industrial and commercial customers.

Gaz Métro owns and operates a LNG Facility, the LSR facility in eastern Montreal. This facility is primarily used to serve customers not hooked up to the pipeline grid and supply LNG for transportation options. This facility has a capacity of 3 Bcf per year with a storage capacity of 25.2 million gallons.

The company does not own or operate its own gas storage facilities, rather it contracts storage capacity on nearby storage fields and contracts for storage capacity with Union Gas. Gaz Métro's contracted gas storage capacity and peak gas deliverability is show in Exhibit A-1 below.

Exhibit A-1: Gaz Métro storage capacity and deliverability

Gas Storage Source	Storage Capacity (Bcf)	Withdrawal Capacity (Dth/d)
LSR (daQ)	2.0	207,000
Pointe-du-Lac	0.9	44,000
Saint-Flavien	4.4	55,000
Union Gas	12.5	205,000
Total	19.8	511,000

Source: Gaz Metro Regulatory Filing - R-3879-2014 D-2015-177

A.1.3 Centra Gas Manitoba:

Centra Gas serves over 270,000 customers in Winnipeg and southern Manitoba¹⁸. Centra Gas customers use approximately 74 Bcf of natural gas during a year, of which nearly 100 percent are delivered from Alberta by a mainline transmission pipeline owned by TransCanada (TCPL).¹⁹

Centra Gas does not own or operate its own gas storage facilities. The company's current 7 year transportation & storage plan outlines a strategy to reduce the amount of Firm Transport Centra Gas holds on the TCPL system and to diversify its gas supply by utilizing gas storage options in the US Midwest via the ANR Pipeline system.

¹⁹ https://www.hydro.mb.ca/corporate/facilities/manitoba hydro naturalgas.shtml



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¹⁸ http://www.pub.gov.mb.ca/pdf/reports/14-15.pdf

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Storage usage criteria

Centra Gas holds contracts for 14.7 Bcf of storage capacity on the ANR pipeline system in Michigan. Storage gas is delivered from Michigan to the Centra Gas service territory in Manitoba via backhaul capacity on ANR Pipeline, Great Lakes Pipeline, and TransCanada Pipeline. The company's contracted storage facilities include:

- 7.7 Bcf of seasonal storage capacity that can be cycled once per year.
- 7.0 Bcf of annual storage with injects/withdrawals that can be cycled 1.4 times annually.
- Delivery capacity of 206,400 Dth/d in the winter season and an injection capacity of 84,000 Dth/d in the summer season.

To support its gas supply needs, Centra Gas holds seasonal pipeline capacity on ANR Pipeline, Great Lakes Pipeline, and TransCanada Pipeline. Pipeline capacity during the summer months includes:

- 50,500 Dth/day on Great Lakes from Emerson, Manitoba to Crystal Falls, MI.
- A firm transport (FT) agreement of 50,200 Dth/d from Crystal Falls to ANR Storage.
- An FT agreement of 7,000 Dth/d on ANR Pipeline from the ANR Joliet Hub, Illinois to ANR Storage in Michigan.

Pipeline capacity during the winter months includes:

- 224,363 Dth/d of FT capacity on Great Lakes from Crystal Falls, MI to Emerson, Manitoba.
- 204,363 Dth/d of FT capacity on ANR Pipeline from ANR Storage to Crystal Falls, MI.
- 40,000 Dth/d of FT capacity on ANR Pipeline from ANR Storage in Michigan to the ANR Joliet Hub, Illinois.

A.1.4 Consumers Energy:

Consumer Energy serves 1.7 million customers across Michigan's Lower Peninsula. Approximately 50 percent of the company's customers are in Detroit, with other major operating areas including Bay City, Flint, Jackson, Kalamazoo, Lansing, Macomb, Midland, Royal Oak, Saginaw and Warren. The company owns and operates over 29,000 miles of distribution and transmission pipelines as well as a network of gas storage facilities. Consumers Energy owns and operates 16 gas storage facilities with a working capacity of 150 Bcf.²⁰

Consumers Energy has access to multiple supply areas. To take advantage of the changing cost and availability of gas supplies, the company has increased purchases of gas from the Midwest and has decreased its reliance on Gulf Coast area gas supplies.

Consumer Energy's gas supply plan is to purchase 75 percent of its annual gas needs during the summer months, injecting the balance into its gas storage fields to meet peak winter needs. The company will meet 50 percent of winter demand utilizing its gas storage fields, with the remainder using its Firm Transportation agreements and citygate purchases.

²⁰ http://www.dleg.state.mi.us/mpsc/gas/storage.htm



Exhibit 1.D1.EGDI.STAFF.10

Attachment

Storage usage criteria

Consumer Energy plans to meet its gas supply needs by reaching a gas storage targets of 175.6 Bcf by end of October and having a remaining balance of 70.1 Bcf by March. Throughout the year the company may make gas purchase adjustments in order to meet its targeted storage levels.

A.1.5 DTE Gas

DTE Gas serves 1.2 million customers across the Upper and Lower Peninsula of Michigan. DTE Gas owns four gas storage fields in Michigan, with total working capacity of 135.1 Bcf. These fields are a mix of base-load and peaking facilities.

To meets its customers gas demand needs, DTE Gas holds 400,000 Dth/d of FT pipeline contracts during the winter and 330,000 Dth/d during the summer injection season. These gas supply purchases are supported by pipeline commitments on ANR, Great Lakes, and Panhandle Eastern. The company has also entered into an agreement to purchase additional gas supplies on Nexus, as well as utilizing local gas purchases.

Storage usage criteria

DTE Gas has a total gas storage field capacity of 135.1 Bcf, with 71.9 Bcf allocated to GCR & GCC customers, and 5 Bcf used for contingency space.²¹ The company operates its gas storage facilities based on the following operating criteria:

- End of injection season target of 135.1 Bcf, 71.9 Bcf for its GCR & GCC customers.
- Minimum Storage Balances of at the end of the month:
 - January: 48.9 Bcf (25.3 Bcf for GCR/GCC).
 - o February: 24.1 Bcf (10.7 Bcf for GCR/GCC).
 - o March: 5 Bcf (3.2 Bcf for GCR/GCC).

A.1.6 National Fuel Gas Distribution

National Fuel Gas Distribution Corporation sells natural gas to more than 740,000 customers, with 540,000 customers in New York and 200,000 customers in Pennsylvania. National Fuel Gas owns and operates 2,877 miles of gas transmission and distribution pipelines. The company also owns and operates 28 natural gas storage facilities with a capacity of 78 Bcf. Exhibit A-2 below shows the company's service area and interstate pipelines serving the area.

²¹ National Fuel Gas Distribution's New York regulatory filing U-16999

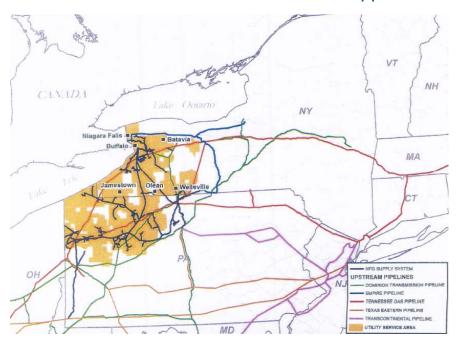


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Exhibit A-2: National Fuel Gas Distribution Service areas and pipeline interconnects



Source: National Fuels Gas Distribution Regulatory Filings - 16-G-0257, exhibit GSA

New York

National Fuel Gas (NY) sourcing strategy is based on a five year planning horizon to assess supply sources and needed capacity. Currently, the company secures its gas supply via upstream capacity on Dominion, Empire, Honeoye Storage Corporation, Tennessee, and Transco, as well as purchasing roughly 5 percent of its supply needs from local production. Over the past several years, gas supply purchases have shifted from sourcing gas supplies at Dawn via TCPL capacity to source gas from the Marcellus/Utica. National Fuel Gas (NY) has two remaining FT agreements with TransCanada.²²

Storage usage criteria

The Company's gas storage portfolio includes storage capacity near its customers on National Fuel Gas and Dominion pipeline systems. These storage assets are used to meet peak winter demand, improve pipeline utilization levels over the summer, and act as a hedge against winter price volatility.²³ The company plans to meet 39 percent of its winter season demand from gas storage deliveries and 61 percent via pipeline deliveries.

²³ Ventyx SENDOUT II is used to evaluate the economic impact of monthly supply options



²² Two TransCanada FT agreements are for 10,141 Dth/d and 14,970 Dth/d of capacity and will terminate on October 31, 2017 and on October 31, 2020.

Exhibit 1.D1.EGDI.STAFF.10

Attachment

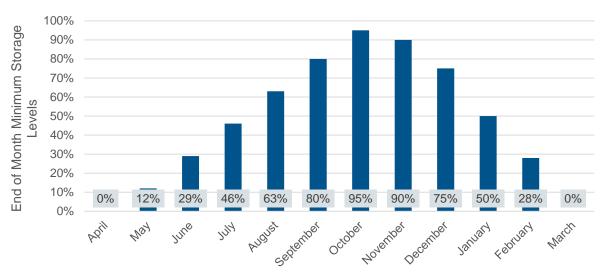
Pennsylvania

Within its Pennsylvania service area, National Fuel Gas (PA) secures its gas supply via upstream capacity on Columbia, Texas Eastern (TETCO²⁴), and Tennessee as well as direct purchases from National Fuel Gas SC. Due to the increase in Marcellus shale gas supplies, the company has increased its local sourcing from 12 percent in 2009 to 24 percent in 2016.

Storage usage criteria

To ensure its ability to meet peak day demand, National Fuels (PA) maintains the minimum storage levels detailed in Exhibit A-3 below.

Exhibit A-3: National Fuel Gas (PA) Gas Storage Level Requirements



Source: National Fuel Gas Distribution's Regulatory Filings - PA PUC R-2016-2521819

A.1.7 Peoples Gas

Peoples Gas serves 828,000 customers in an around the City of Chicago. The company owns and operates the Manlove Field with a capacity of 36.5 Bcf. This field accounts for 52 percent of the capacity of Peoples Gas' gas storage portfolio, with the remainder of capacity contracted with third parties ANR and Washington 10. The company also owns and operates an LNG facility as part of its Manlove Field complex. The company stores LNG in two tanks, which have a capacity of 12 million gallons, equivalent of 1 Bcf. Vaporized LNG is used to support peak day needs.

The company has firm transportation contracts on a variety of pipelines, including ANR Pipeline Company, Gulfstream Natural Gas System, Kinder Morgan Illinois Pipeline, and Vector Pipeline. In recent years Peoples Gas has been reducing the levels of contracted pipeline capacity and increasing its purchases of local gas supplies in the Chicago area.

²⁴ National Fuel (PA) recently added additional Firm Transport capacity on TETCO, increasing capacity from 10,000 Dth/d to 20,000 Dth/d to support peak demand



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Peoples Gas uses several modelling forecasts as part of its gas supply planning process, including; a peak day forecast, a long-term gas requirements, and a gas sendout forecast as part of a Gas Dispatch Model that calculates a daily withdrawal requirements. These modelling efforts are designed to support the lowest cost of gas over an annual period.²⁵

Storage usage criteria

Peoples Gas begins each season with established storage targets based on normal weather. These storage targets are flexible and are revisited throughout the season to account for weather, estimated customer-owned gas deliveries, and assumptions for other factors not precisely known when the storage plan was initially set.

Due to the characteristics of the Manlove field, which is an aquifer storage, the company does follow strict seasonal patterns of withdrawal and injections. Despite seasonal guidelines, there is significant flexibility in the daily sendout volumes.

A.1.8 Ameren (IL)

Ameren (IL) serves 816,000 natural-gas customers across central and southern Illinois. The company owns 18,200 miles of natural gas transmission and distribution, as well as 12 underground natural gas storage fields (5 aquifer reservoirs and 7 depleted gas reservoirs). These gas storage facilities support peak deliverability of 570,000 Dth/d from 24.2 Bcf of working storage capacity. In addition to on-system storage, the company also contracts for gas storage services with interstate pipelines.

The company's distribution systems is connected to 10 different interstate pipeline systems – Panhandle Eastern Pipe Line, Texas Eastern, Trunkline, Natural Gas Pipeline Company of America, Northern Border Pipeline, American Natural Resources Pipeline, Texas Gas Transmission, Mississippi River Transmission Company, Rockies Express Pipeline and Midwestern Gas Transmission Company – which allow for supply diversity gas purchases and the ability to meet demand on peak days.

Ameren Illinois uses a six-year planning horizon for its gas supply purchases and hedging practices. The primary goal of the company's planning process is to minimize price disruptions, using a layering approach for its gas purchases, which both reduces volatility and allows for the flexibility to respond to changes in the market place.

Storage usage criteria

Ameren's gas storage plan targets for its owned and contracted storage to be 100 percent full on November 15th. During the 2014-15 winter season, Ameren targeted a storage level of 36.5 Bcf in November, with 23.5 Bcf on company owned Storage assets. This level of storage capacity allows Ameren to meet approximately 50 percent of its normal winter requirements via gas storage withdrawals, providing a balance between storage withdrawals and purchased gas supply during the winter season.

²⁵ People Gas' Regulatory Filings - Docket No. 14-0736, PGL Ex. 1.0



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A core part of the company's gas storage plan is the use of leased storage. Ameren will vary leased storage activity in order to minimizing pipeline balancing penalties in response to changes in firm sales customer requirements.

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Ameren's seasonal gas storage injection and withdrawal schedules are developed to ensure the storage facilities are able to provide adequate reliability, protect the integrity of the reservoir, and minimize the overall supply costs. The Company relies on operational experience, historical performance data, and models to ensure that maximum productivity is achieved from its storage fields.

A.1.9 Nicor Gas

Nicor Gas transports and stores natural gas for 129,000 commercial and industrial customers across northern Illinois. The company controls over 34,037 miles of natural gas transmission and distribution pipelines, and owns eight gas storage fields with a total storage capacity of 150 Bcf. The company also purchases contracted storage services from interstate pipelines. Nicor's on-system storage provides critical peak day, peak hour and durational supply.

Nicor's gas system is operated in a manner to maximize access to available pipeline deliveries and features high levels of firm contracting for gas supply purchases. The company possesses interconnects with 8 interstate pipeline systems – Natural Gas Pipeline Company of America, Midwestern Gas Transmission, Northern Natural, Panhandle Eastern, ANR, Northern Border, Alliance, and Horizon Pipeline – which provide significant flexibility in securing a variety of gas supplies.

Nicor uses a gas purchasing strategy that is based on the following four factors:

- Peak Design Day and monthly sendout requirements.
- The timing of monthly gas purchases (injection/withdrawals) to support an appropriate gas storage inventory and sufficient deliverability to meet a significant portion of daily and seasonal winter peak loads.
- Estimates for third party volume and system requirements to Nicor's gas storage assets.
- The mix of supply contracts in its portfolio based on the available price information and the need for system flexibility to adjust to changing conditions on a seasonal, monthly, and daily basis.

Nicor uses a variety of computer models and other analytical methods common to the industry to model seasonal and Peak Design Day Requirements for gas demand for its customers and third-party requirements on its natural gas systems.

Storage usage criteria

The company's storage usage plan is developed following the completion of Nicor's seasonal supply requirements. The level of baseload and daily purchases are established to address supply security concerns and mitigate price volatility, while affording flexibility to accommodate changes due to weather and third party activity.



Exhibit 1.D1.EGDI.STAFF.10

Part of Nicor's gas storage plan is to ensure that aquifer performance is maintained and related Attachment aquifer pressures are able to meet peak, seasonal, and daily needs, via appropriate storage injection/withdrawal schedules. These schedules are established based on operational experience and historical aquifer performance data.

The company's gas storage usage plan is to have the on-system storage filled by November the 10th. The company's storage assets will be managed to ensure the assets are able to meet Peak Design Day withdrawal requirements through January 20th, and are still able to meet post-design day peak requirements through March 15th, while still meeting the seasonal withdrawal targets.

A.1.10 MidAmerican Energy

MidAmerican Energy is a large gas distributor, serving 733,000 customers across Iowa, Illinois, South Dakota and Nebraska. MidAmerican Energy's regulated Illinois Gas Distribution Company does not own or operate its own gas storage facilities. The company has access to multiple supply sources via the Northern Natural, NGPL, Northern Border, ANR, and Alliance pipeline systems.

The company's Peak Design Day gas supply includes the following breakout;

- 50 to 55 percent from FT gas supply purchases.
- 30 to 35 percent from withdrawals on leased storage facilities.
- 10 to 15 percent from peaking facilities (LNG).
- 0 to 10 percent from Citygate purchase.



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Appendix B: Natural Gas Prices at Dawn for the Three Attachment Alternative Weather Scenarios

Exhibit B-0-1: Natural Gas Prices at Dawn for the Three Enbridge Weather Scenarios								
US\$/MMBtu	Warm Weather Case	Budget Weather Case	Cold Weather Case					
April-17	3.60	3.89	3.21					
May-17	3.15	3.09	2.97					
June-17	2.92	2.78	2.82					
July-17	2.71	2.62	2.64					
August-17	2.72	2.66	2.64					
September-17	2.94	2.82	2.92					
October-17	3.43	3.49	3.37					
November-17	3.23	3.32	3.26					
December-17	3.22	3.29	3.29					
January-18	3.20	3.38	3.89					
February-18	2.78	3.49	4.72					
March-18	2.43	3.35	4.43					
April-18	2.72	3.24	3.88					
May-18	2.30	2.70	2.95					
June-18	2.38	2.66	2.96					
July-18	2.50	2.69	2.74					
August-18	2.52	2.72	2.71					
September-18	2.43	2.73	2.77					
October-18	2.71	3.20	3.39					
November-18	3.66	3.77	4.07					
December-18	3.66	3.73	4.09					
January-19	4.14	4.12	4.96					
February-19	4.23	4.33	6.13					
March-19	4.02	4.14	4.78					
April-19	3.58	4.12	4.27					
May-19	2.97	3.11	3.24					
June-19	2.83	2.93	3.05					
July-19	2.97	2.87	2.92					
August-19	2.97	3.00	2.92					
September-19	2.85	2.88	2.89					
October-19	3.28	3.26	3.52					
November-19	4.01	4.18	4.52					
December-19	4.04	4.11	4.63					
January-20	4.73	4.58	5.23					
February-20	5.04	4.77	6.01					
March-20	5.07	4.45	4.55					
April-20	4.26	4.46	4.24					
May-20	3.47	3.34	3.30					
June-20	3.28	3.24	3.18					
July-20	3.42	3.24	3.22					
August-20	3.49	3.44	3.30					
September-20	3.19	3.06	3.02					
October-20	3.88	3.59	3.73					
COLONGI LO	3.00	3.55	3.73					

Source: ICF GMM®



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Appendix C: Assumptions behind ICF's Natural Gas Page 56 of 64 Market Outlook - April 2016

Exhibit C-1: Pipelines in the Planning Stages near Ontario

Project(s)	From	То	Capacity (MMcfd)	Year				
Capacity to Ontario from Outside the Province								
Rover/Nexus *	Marcellus/Utica	Vector Pipeline	1050	2017				
Within Ontario								
TCPL Niagara Expansion 2016	Niagara/ <u>Chippawa</u>	Parkway	380	2017				
TCPL Vaughan Loop	Parkway	Maple	445	2017				
Maple Compression	Parkway	Maple	438	2017				
Energy East Conversion	Western Ontario	Quebec	-1140	2019				
TCPL Eastern Mainline Expansion	Parkway	Iroquois/Waddington	672	2019				
	To Nort	heast/New England						
Dominion New Market Expansion	Marcellus Interconnects	Upstate New York	112	2016				
National Fuel Northern Access	Pennsylvania	Western New York	497	2017				
Atlantic Bridge	Marcellus	New England & Maritimes	300					
Constitution	Northeast Pennsylvania	Wright, New York	650	2018 (inactive)				
Wright Interconnect	Schoharie County, NY	Into Iroquois and TGP	uois and TGP 650					
South to North	Wright, New York	Waddington, New York	650	2018 (inactive)				
Access Northeast Marcellus		New England	500 (+400 Peak shaving capacity)	2018				
Diamond East	Marcellus	New Jersey	1,000	2018				
Penneast Pipeline	Marcellus Interconnects	New Jersey	1,000	2018				
Millennium Upgrade	Marcellus Interconnects	New York	200	2018				
PNGTS C2C Expansion	Quebec	New England	130	2017				

^{*} Where there are multiple projects competing to add capacity on the same path, the capacity shown is the total amount expected by 2018.

Source: ICF, compiled from various public announcements.



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Appendix D: ICF's Gas Market Model (GMM)

ICF's Gas Market Model (GMM) is an internationally recognized modeling and market analysis system for the North American gas market. The GMM was developed in the mid- 1990s to provide forecasts of the U.S. and Canada natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. Subsequently, GMM has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

In addition to its use for strategic planning studies, the model has been widely used by a number of institutional clients and advisory councils, including Interstate Natural Gas Association of America (INGAA), which has relied on the GMM for multiple studies over the past ten years. The model was also the primary tool used to complete the widely referenced study on the North American Gas market for the National Petroleum Council in 2003, and the 2010 Natural Gas Market Review for the Ontario Energy Board.

GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure D-1) Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, ICF does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

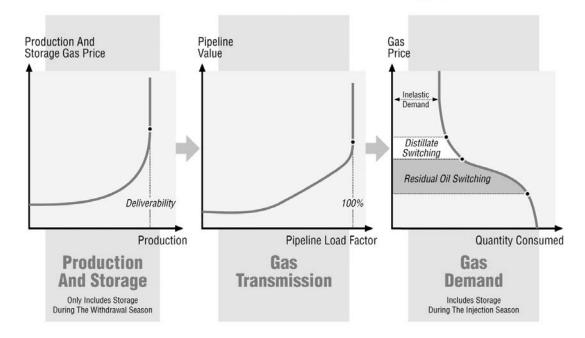


Filed: 2017-11-13 EB-2017-0086 Exhibit 1.D1.EGDI.STAFF.10 Attachment Page 58 of 64

Figure D-1: ICF's Gas Market Data and Forecasting System

Gas Quantity And Price Response

EEA's Gas Market Data And Forecasting System



There are nine different components of GMM, as shown in Figure D-2. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. ICF's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.



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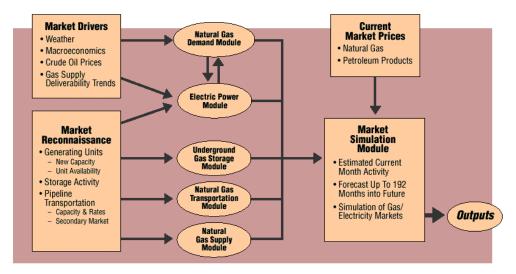


Figure D-2: GMM Components

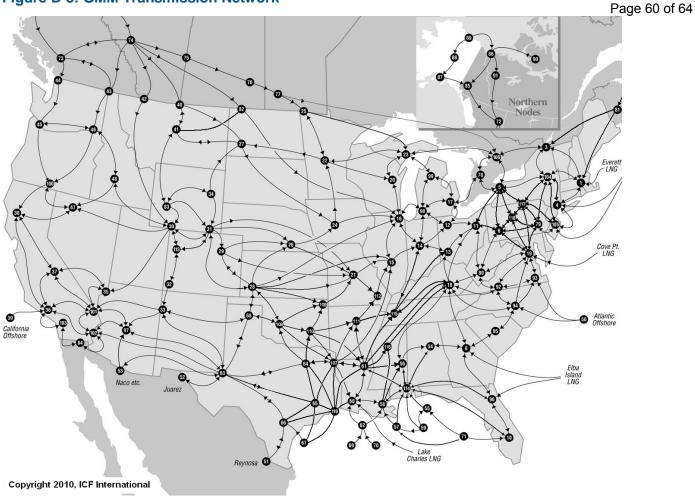
The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure D-3, and the detailed structure in the Marcellus/Utica area is show in Figure D-4. The gas supply component of the model solves for node-level natural gas deliverability or supply capability, including LNG import and export levels. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.



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Attachment

Figure D-3: GMM Transmission Network



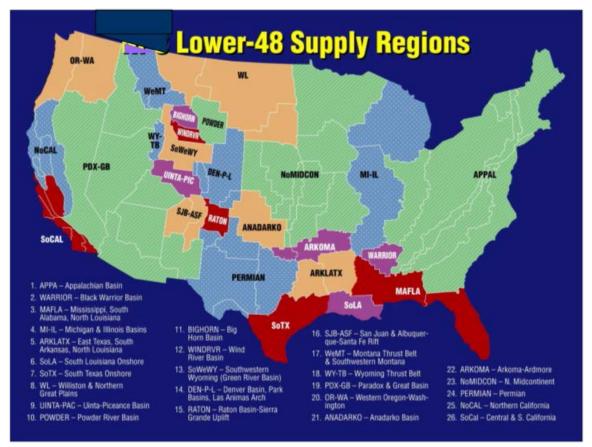
ICF Natural Gas Supply Assessment Methodology

ICF's Natural Gas Supply Assessment Methodology (ISAM) covers the Continental United States, Alaska and Canada. The Continental United States is represented in 28 onshore regions (see Figure D-5) and 11 offshore regions.



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Figure D-4: NPC Continental US Supply Regions



Alaska is divided into seven regions and Canada is divided into ten regions. All regions are further broken out into subregions or "intervals." They represent some combination of drilling depths, water depth, or geographic areas.

Resources are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

New Fields

New discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields, and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon makeup containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are oil, sweet nonassociated gas, or sour nonassociated gas.

The methodology uses a modified "Arps-Roberts" equation to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its areal extent,



Exhibit 1.D1.EGDI.STAFF.10

which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be Attachment found earlier in the discovery process than smaller fields. The new equation developed by ICF Page 62 of 64 accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas, the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas.

The find-rate equations are used in the model to predict the number of fields of a certain size that will be discovered after a given number of exploratory wells have been drilled. There are separate equations for each field-size class (e.g., size class 6 is between one and two million barrels of oil equivalent) within each depth interval, within each region. The Continental US portion of the model alone has over 3,000 separate find-rate equations. This is a very fine level of detail given that actual annual new field discoveries have been below 600 fields in recent years.

An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax discounted cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. There are about 7,000 prototype field development plans in the model for the Continental US that include all capital and operating costs and production timing specifications built up from historical data. The economic decision to develop a field is made using "sunk cost" economics where the discovery cost are ignored and only time-forward development costs and production revenues are considered. However, the model's decision to begin an exploration program includes all exploration and development costs.

The results for new field exploration are reported in standard output tables that show the marginal economics (internal rate of return and resource cost) of exploration in each region and interval throughout the forecast. There are also outputs in Excel and Access format showing the number of fields being found, recoverable hydrocarbons discovered and recoverable hydrocarbons developed.

Unconventional Gas

The ICF assessment method for shale gas is a "bottom-up" approach that first generates estimates of unrisked and risked gas-in-place (GIP) from maps of depth, thickness, organic content, and thermal maturity. Then, ICF uses a different model to estimate well recoveries and production profiles. Unrisked GIP is the amount of original gas-in-place determined to be present based upon geological factors— without risk reductions. "Risked GIP" includes a factor to reduce the total gas volume on the basis of proximity to existing production and geologic factors such as net thickness (e.g., remote areas, thinner areas, and areas of high thermal maturity have higher risk). ICF calibrates expected well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data. In late 2011, ICF undertook an extensive analysis of Marcellus well recoveries and compared them with model results with good correlation. ICF confirmed that the model well recoveries are conservative. Additional analysis in 2012 also confirmed these results.



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Major Unconventional Natural Gas Categories

Definition of Unconventional Gas: Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.

Tight Gas is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

Coalbed Methane is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

Shale Gas is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale

Upstream Cost and Technology Factors

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items.



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Enbridge Gas Storage Assessment

Potential Value of Incremental Storage Capacity for Enbridge Gas



Exhibit I.D1.EGDI.STAFF.11

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BOARD STAFF INTERROGATORY #11

INTERROGATORY

Ref: Operating Costs – Customer Care / CIS Update Exhibit D1 / Tab 3 / Schedule 1

Preamble:

The definition of customer used for determining Customer Care / CIS revenue requirement includes both active and locked customers.

Question(s):

a) Please explain how the combined active and locked customer count (2,197,291) is derived.

RESPONSE

The active component is based on the Unlocks customer count. The locked component is based on a historical average of the count of locked meters during the year. These accounts are included as there are ongoing customer care costs to service customers with locked meters.

Witness: D. McIlwraith

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.12

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BOARD STAFF INTERROGATORY #12

INTERROGATORY

Ref: Operating Costs – DSM Budget Update Exhibit D1 / Tab 4 / Schedule 1

Preamble:

Enbridge noted that in the EB-2015-0049 Decision, the OEB approved a 2017 DSM budget of \$67.6 million.

Question(s):

a) Please confirm that the DSM budget of \$67.6 million is the amount included in the 2018 allowed revenue in accordance with Schedule A of the EB-2015-0049 Decision and Order.

RESPONSE

The Company confirms, as shown at Exhibit D1, Tab 1, Schedule 2, page 2, that the EB-2015-0049 Approved 2018 DSM budget of \$67.6 million is the amount included in the determination of 2018 updated forecast allowed revenue.

Witnesses: E. Reimer

R. Small

Exhibit I.D1.EGDI.STAFF.13

Page 1 of 1

BOARD STAFF INTERROGATORY #13

INTERROGATORY

Ref: Operating Costs – Pension / OPEB Update Exhibit D1 / Tab 5 / Schedule 1 Updated

Preamble:

Enbridge noted that it undertook a review of pension plan design following the acquisition of Spectra Energy in order to harmonize programs for employees of both companies. Enbridge stated that the harmonized plan will be effective January 1, 2018. The costs of the new pension plan for 2018 (on both an accrual and cash basis) are set out in Enbridge's evidence at Exhibit D1 / Tab 5 / Schedule 1 / Appendix 1 Updated.

Question(s):

- a) Please provide an explanation supporting the inclusion of the pension plan changes arising from the acquisition of Spectra Energy as an update to the 2018 Pension / OPEB expenses in the context that 2018 is the final year of the current Custom IR term.
- b) Please provide an estimate of the 2018 Pension / OPEB expenses (on both an accrual and cash basis) assuming there had been no acquisition of Spectra Energy (and therefore, Enbridge had not harmonized its pension plan).

RESPONSE

- a) The new plan is effective for Enbridge Gas Distribution employees on January 1, 2018, therefore, it is appropriate to reflect in 2018 expenses. The principle of updating and truing up pension and OPEB costs each year is to ensure that ratepayers pay only the actual costs for these items. The Company did not delay implementation because the changes improve the long-term financial sustainability of the pension plan by introducing a 5 year DC participation period for new hires and by eliminating cost of living adjustments ("COLA") for future service.
- b) Please refer to the response to BOMA Interrogatory 29(c) for the estimated impact for 2018 forecasted accrual expense and forecasted cash requirement.

Witnesses: Mercer

R. Stelmaschuk

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.14

Page 1 of 2 Plus Attachments

BOARD STAFF INTERROGATORY #14

INTERROGATORY

Ref: Operating Costs – Utility Taxable Income and Income Tax Expense Exhibit D1 / Tab 6 / Schedule 1

Preamble:

Enbridge noted that it removed the 2018 placeholder tax deduction (\$31.1 million) for the site restoration cost (SRC) adjustment. The removal of the noted tax deduction is in accordance with Enbridge's proposal to discontinue Rider D in 2018 (and to move the tax deduction from 2018 allowed revenue to the Constant Dollar Net Salvage Adjustment Deferral Account).

Question(s):

- a) Please provide Exhibit D1 / Tab 6 / Schedule 2 with the \$31.1 million SRC adjustment related tax deduction included.
- b) Please provide a revised 2018 allowed revenue and sufficiency / deficiency schedule (Exhibit A1 / Tab 3 / Schedule 1 / Appendix B) with the income tax line based on the inclusion of \$31.1 million SRC-related tax deduction.
- c) c) Please provide revised bill impacts for a typical Rate 1 and Rate 6 customer with the SRC-related tax deduction included in the 2018 allowed revenue.

<u>RESPONSE</u>

- a) Please refer to Attachment #1 which replicates Exhibit D1 / Tab 6 / Schedule 2 under the assumption that the 2018 \$31.1 million SRC adjustment related tax deduction is included.
- b) Please refer to Attachment #2 which replicates Exhibit F1 / Tab 2 / Schedule 1 (which is comparable to A1 / Tab 3 / Schedule 1 / Appendix B but segregates CIS/Customer Care amounts), under the assumption that the 2018 \$31.1 million SRC adjustment related tax deduction is included.

Witnesses: A. Kacicnik

R. Small

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Plus Attachments

c) As outlined in Attachment #2 to response b) above, the 2018 revenue deficiency would equal \$74.7 million assuming the SRC-related tax deduction was included in the 2018 revenue requirement calculation.

The following table compares:

• The Company's as-filed rate and bill impacts found at Exhibit H2, Tab 8, Schedule 1 versus the scenario with the SRC-related tax reduction included in the 2018 revenue requirement calculation. These are found below under the headings for Rate 1 and 6 excluding the SRC Credit. Please note, however, that the ultimate bill impacts for customers in 2018 will be same under either scenario – under Enbridge's proposal (the as-filed scenario), the impact of the SRC-related tax deduction will be credited at the time that deferral and variance accounts are cleared (likely in October 2018).

		As Filed Deficie	ency of \$8	6 M	Scenario Deficiency of \$74.7 M			
		Rate Impact	Rate Impact Bill Impact		Rate Impact	Bill Impact		
Rate 1 excluding SRC Credit								
Sales		3.2%	\$ 2	8.3	2.8%	\$	24.5	
T-Service		4.8%	\$ 2	8.7	4.2%	\$	24.9	
Rate 6 exc	luding SRC Credit							
Sales	<u> </u>	2.4%	\$ 15	9.6	2.1%	\$	139.7	
T-Service		4.3%	\$ 16	3.0	3.8%	\$	143.3	

Witnesses: A. Kacicnik

R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.14 Attachment 1 Page 1 of 1

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE 2018 UPDATED FORECAST (EXCLUDING CIS & CUSTOMER CARE)

		Col. 1	Col. 2	Col. 3
		ED 0040 0450	0040	0040
		EB-2012-0459 2018 Utility	2018 CIR	2018 Updated
Line		Placeholder	_	Forecast
No.		Tax	Update	
INO.		(\$Millions)	Adjustments (\$Millions)	Utility Tax (\$Millions)
		(Філішоце)	(\$10111110115)	(ФIVIIIIOTIS)
1.	Utility income before income taxes	323.7	27.1	350.8
	Add			
2.	Depreciation and amortization	292.8	-	292.8
3.	Accrual based pension and OPEB costs	26.2	(5.4)	20.8
4.	Other non-deductible items	1.0		1.0
5.	Total Add Back	320.0	(5.4)	314.6
6.	Sub total	643.7	21.7	665.4
0.	Sub total	043.7	21.7	003.4
	Deduct			
7.	Capital cost allowance - Federal	298.5	-	298.5
8.	Capital cost allowance - Provincial	298.5	-	298.5
9.	Items capitalized for regulatory purposes	46.6	-	46.6
10.	Deduction for "grossed up" Part VI.1 tax	5.6	(2.2)	3.4
11.	Amortization of share/debenture issue expense	4.0	0.7	4.7
12.	Amortization of cumulative eligible capital	4.5	_	4.5
13.	Amortization of C.D.E. and C.O.G.P.E	0.1	_	0.1
14.	Site restoration cost adjustment	31.1	_	31.1
15.	Cash based pension and OPEB costs	29.8	(2.9)	26.9
-	Total Deduction - Federal	420.2	(4.4)	415.8
17.		420.2	(4.4)	415.8
17.	Total Deduction - Flovincial	420.2	(4.4)	413.0
18.	Taxable income - Federal	223.5	26.1	249.6
19.	Taxable income - Provincial	223.5	26.1	249.6
20.	Income tax rate - Federal	15.00%	0.00%	15.00%
21.	Income tax rate - Provincial	11.50%	0.00%	11.50%
	Income tax provision - Federal	33.5	3.9	37.4
23.	Income tax provision - Provincial	25.7	3.0	28.7
24.	Income tax provision - combined	59.2	6.9	66.1
25.	Part V1.1 tax	1.9	(0.9)	1.0
26.	Total taxes excluding tax shield on interest expense	61.1	6.0	67.1
	Tax shield on interest expense			
27.	Rate base	6 1 1 5 6	93.5	6,239.1
		6,145.6 3.34%		
28.	Return component of debt		-0.42%	2.92%
29.	Interest expense	205.5	(23.2)	182.3
30.	Combined tax rate	26.50%	0.00%	26.50%
31.	Income tax credit	(54.5)	6.2	(48.3)
32.	Total income taxes	6.6	12.2	18.8

Witnesses: A. Kacicnik R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.STAFF.14

Attachment 2 Page 1 of 1

ALLOWED REVENUE AND SUFFICIENCY/(DEFICIENCY) 2018 UPDATED FORECAST

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
Line No.		EB-2012-0459 Excl. CIS 2018 Allowed Revenue Placeholder (\$Millions)	EB-2012-0459 CIS 2018 Allowed Revenue Placeholder (\$Millions)	EB-2012-0459 2018 Total Allowed Revenue Placeholder (\$Millions)	2018 CIR Updates Excl. CIS (\$Millions)	2018 CIR Updates for CIS (\$Millions)	2018 Updated Forecast Allowed Revenue Excl. CIS (\$Millions)	2018 Approved CIS Allowed Revenue (\$Millions)	2018 Total Updated Forecast Allowed Revenue (\$Millions)
	Cost of capital								
1. 2. 3.	Rate base Required rate of return	6,145.6 7.12 437.6	7.0 6.44 0.5	6,152.6 7.12 438.1	93.5 (0.97) (54.0)	- - -	6,239.1 6.15 383.6	7.0 6.44 0.5	6,246.1 6.15 384.1
	Cost of service								
4. 5. 6. 7. 8. 9.	Gas costs Operation and maintenance Depreciation and amortization Fixed financing costs Municipal and other taxes	1,632.5 334.3 292.8 1.9 50.4 2,311.9	108.5 12.7 - - 121.2	1,632.5 442.8 305.5 1.9 50.4 2,433.1	122.4 27.3 - - - 149.7	(2.6)	1,754.9 361.6 292.8 1.9 50.4 2,461.6	105.9 12.7 - - 118.6	1,754.9 467.5 305.5 1.9 50.4 2,580.2
	Miscellaneous operating and non-operating revenue								
10. 11. 12. 13.	Interest and property rental Other income	(42.7) - (0.1) (42.8)	- - -	(42.7) - (0.1) (42.8)	- - -	- - -	(42.7) - (0.1) (42.8)	- - -	(42.7) - (0.1) (42.8)
	Income taxes on earnings								
14. 15. 16.		61.1 (54.5) 6.6	7.2 (0.1) 7.1	68.3 (54.6) 13.7	6.0 6.2 12.2		67.1 (48.3) 18.8	7.2 (0.1) 7.1	74.3 (48.4) 25.9
	Taxes on sufficiency / (deficiency)								
17. 18. 19.		(163.6) (120.3) 43.4	- -	(163.6) (120.3) 43.4	93.4 68.7 (24.8)	- - -	(70.2) (51.6) 18.6	- - -	(70.2) (51.6) 18.6
20. 21.	Sub-total revenue requirement Customer Care Rate Smoothing V/A Adjustment	2,756.7	128.8 5.0	2,885.5 5.0	83.1	(2.6) (0.1)	2,839.8	126.2 4.9	2,966.0 4.9
22.	Allowed revenue	2,756.7	133.8	2,890.5	83.1	(2.7)	2,839.8	131.1	2,970.9
	Revenue at existing Rates								
24. 25. 26.	•	2,404.4 186.6 1.8 0.3 2,593.1	91.8 18.4 - - 110.2	2,496.2 205.0 1.8 0.3 2,703.3	103.8 55.6 17.4 (0.3)	25.2 (8.8) - - 16.4	2,508.2 242.2 19.2 	117.0 9.6 - - 126.6	2,625.2 251.8 19.2 - 2,896.2
	Gross revenue sufficiency / (deficiency)	(163.6)	(23.6)	(187.2)	93.4	19.1	(70.2)	(4.5)	(74.7)

Witnesses: A. Kacicnik R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.APPrO.1 Page 1 of 2

APPrO INTERROGATORY #1

<u>INTERROGATORY</u>

Reference:

- i) Exhibit D1 Tab 2 Schedule 3 paragraph 36 states: For 2018 Enbridge has used a gross heating value of 38.42 MJ/m3 to convert quantities (i.e., GJ, Dth) into volumes (i.e.,103m3, MMcf). Quantities are the units specified in many of Enbridge's gas purchase and transportation service agreements, whereas Enbridge rates are volumetric. Enbridge also committed to use an updated monthly heat value for purposes of converting Direct Purchase deliveries from GJ's to m3 for Banked Gas Reporting.
- ii) Exhibit D1 Tab 2 Schedule 11 paragraph 39
 For the purposes of developing its 2018 gas supply costs, the Company has used a conversion factor of 38.42 MJ/m3, which is more closely aligned with recent heat value observations made by the Company.
- iii) Exhibit H2 Tab 6 Schedule 1 Page 48 of the Rate Handbook states: The conversion factor is 37.74MJ/m3, which corresponds to Union Gas' System Wide Average Heating Value, as per the Board's RP-1999-0017 Decision with Reasons

Preamble: In Reference ii), Enbridge discusses the average heat content for system supplies. In Reference i) Enbridge also indicates that this same 38.42 MJ/m3 will be used for conversion of volumes in transportation agreements. Reference iii) mentions Union's system wide heat content. APPrO would like to understand the implications of these conversion factors for a direct purchase customer that has sourced natural gas from Dawn and delivered to Enbridge via Union and/or TransCanada.

- a) Please describe how Enbridge's system wide average heat content is calculated. In particular please note if this heat content is based on volume weighted average system purchases at the respective points of purchase or some other methodology.
- b) Please confirm that deliveries to Enbridge from both Union and TransCanada are energy based in GJs.
- c) Which heat content does Enbridge use for a direct purchase customer to convert energy to volume when the customer delivers gas to the Enbridge system from either Union and/or TransCanada? How does this heat content compare to the heat

Exhibit I.D1.EGDI.APPrO.1

Page 2 of 2

content used by the pipeline immediately upstream of the Enbridge distribution system.

d) Please describe the implications, if any, and provide by way of numerical example, the impact on the ultimate energy delivered by Enbridge to a direct purchase customer using Enbridge's heat content referred to in c) above. For the numerical example, please assume that the direct purchase customer requires 1,000 GJs of energy to be delivered to its meter.

RESPONSE

a), b), and c)

As a part of the Settlement Agreement in the 2017 Rate Application (see EB-2016-0215 Exhibit N1, Tab 1, Schedule 1, page 10 of 15), EGD committed to update the heat value on a yearly basis for purposes of developing its gas supply plan, for Direct Purchase contract renewals and to update on a monthly basis the heat value used for the purposes of calculating the Banked Gas Account ("BGA") reporting.

On a monthly basis, EGD calculates an average heat value based upon volumes flowing into the distribution system via Union and the various TCPL gate stations for that month. As described in the Settlement Agreement, for the purposes of developing its gas supply plan the Company will use an updated heat value each year based upon the average heat value for the twelve month ending March 31st. This same average heat value will then be used to calculate individual "pool deliveries" as Direct Purchase agreements renew or new pools are established effective July 1st of every year.

On a monthly basis the average heat value of the deliveries into the EGD system will be used for purposes of converting a Direct Purchase customers delivery in GJ's to m³ for BGA reporting. This will provide a better representation of the actual consumption in that particular "pool".

d) The Company does not have the ability to determine the location of each individual customer delivery and measure the actual heat value, nor can it calculate the heat value of the deliveries of individual Direct Purchase customers. The Company believes that the Settlement Agreement approach for calculating BGA balances is a better representation of deliveries and consumption compared to the old method of using 37.69 MJ / m³.

Exhibit I.D1.EGDI.APPrO.3

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APPrO INTERROGATORY #3

<u>INTERROGATORY</u>

Reference: i) Exhibit D1 Tab 2 Schedule 4,

ii) Rate Handbook Exhibit H2 Tab 6 Schedule 1

<u>Preamble</u>: Enbridge illustrates the actual unaccounted for gas (UAF) volumes in graphic

format in Figure 1, including a trend line for the period post 2001. APPrO

would like to better understand this trend.

a) The trend line that was illustrated Figure 1 shows the trend line 2002-2016. All of the actual observations after approximately 2007 have been higher than the illustrated trend line. Please explain how this trend line was developed and why it is still appropriate?

b) Enbridge notes that:

the Settlement Proposal for EB-2015-0114, parties agreed that it is not appropriate to update UAF forecasting methodology during the Custom IR term

Given that the IR term is proposed to end in 2018, please indicate how Enbridge will be addressing UAF at the end of the IR term.

c) Please confirm that for all new construction projects, and in particular the GTA reinforcement project, Enbridge purchases an amount of incremental gas supply for the initial 'fill' of the pipelines up to the operating pressure of the pipe, rather than treating this gas as UAF. Enbridge discusses the differences in gate station measurement between TransCanada's meters and Enbridge's check measurement meters, and states that this difference:

only represents a .75% metering variance

This statement seems to suggest that this difference in metering may be insignificant. Given that Enbridge's total proposed UAF percentage from its Rate Handbook is 0.70%, please explain why this level of difference in measurement with TransCanada meters is not significant?

e) Enbridge receives significant volumes directly from Union Gas; has Enbridge also compared metering differences between Union and Enbridge. If so, please provide the results. If not please explain.

Witnesses: K. Culbert

A. Kacicnik

D. Small

M. Suarez

Exhibit I.D1.EGDI.APPrO.3

Page 2 of 2

f) For all the rate classes listed in the Rate Handbook, please indicate if any of the rate classes do not attract a UAF fee in some form. If there are any that do not attract a UAF fee, please explain why.

RESPONSE

- a) Figure 1 is used to convey the general trends in UAF over time and is for illustrative purposes only. The trend line for 2002 2016 shows that UAF has been trending on a positive slope since 2002. However, the UAF forecast is not developed from this trend line and is instead determined by the regression model that was approved as a part of the 2015 Rate Application (EB-2014-0276).
- b) This question is not relevant to the 2018 Rate Adjustment Application.
- c) UAF is the volumetric difference between the TCPL and Union custody meters i.e., the volume billed to Enbridge, and the meter consumption and the customer's end use location. The 0.70 % identified as part of Rate 300 in the Handbook is intended to capture the difference between the volume delivered to EGD by the Unbundled customer via TCPL and the billed consumption at the Unbundled customers end use location. The daily difference between the Custody meter and the Company's check meter is within Measurement Canada specifications and as stated by EGD if through further review and analysis there is no evidence to suggest meter error then the Custody meter information would not change and therefore, there would be no change to UAF.
- e) Please see response to Energy Probe Interrogatory # 6 (Exhibit I.D1.EGDI.EP.6)
- f) For Rate 125 dedicated service, the UAF is not applicable (it is the only service which does not attract a UAF fee in some form). For Rate 125 customers who receive dedicated service there is no UAF requirement because the metering occurs at the location of interconnection with the Enbridge Gas Distribution system.

Witnesses: K. Culbert

A. Kacicnik D. Small M. Suarez

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.16 Page 1 of 1

BOMA INTERROGATORY #16

<u>INTERROGATORY</u>

Ref: Exhibit D1, Tab 2, Schedule 11, p3

What is the status of the Vaughan Mainline Express Project completion date, and for the Rover Pipeline completion date?

RESPONSE

Please see response to Energy Probe #7 (Exhibit I.D1.EGDI.EP.7)

Exhibit I.D1.EGDI.BOMA.17

Page 1 of 1

BOMA INTERROGATORY #17

INTERROGATORY

Exhibit D1, Tab 2, Schedule 2, pp8-9

Please explain the reason for using the eighteen multi-peaks in the 2018 Supply Plan and show their directional impact on the Gas Supply Plan and ensuing contracts for commodity and transportation, relative to using a single peak day demand.

RESPONSE

The 2018 Gas Supply Plan was developed consistent with prior years whereby 18 multipeaks are included as part of the Company's Design Criteria. The multipeaks are utilized to derive the demand profile underpinning the 2018 Gas Supply Plan.

In 2015, the Company updated the gas supply planning process. Prior to 2015, the Company's gas supply plan ensured that storage deliverability was maintained such that demand for each of the multi-peaks could be met. This meant that over the winter period storage deliverability declined from January to March. The Board approved a change in the 2015 Rate Adjustment Proceeding (EB-2015-0276) that removed this declining storage deliverability planning assumption. Since that time, the planning assumption has been that maximum deliverability from storage is assumed until the end of February and deliverability required to meet a March peak day is assumed until the end of March. Consequently, the use of a single peak does not have any meaningful impact on commodity or transportation because the new storage deliverability assumptions allow for all multi-peak demands to be met.

¹ EBRO 490, Exhibit D2, Tab 15, Schedule 1

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.18 Page 1 of 3

BOMA INTERROGATORY #18

INTERROGATORY

Ref: Ibid, p10

- (a) Why is longer recurrence interval assumption associated with a more conservative gas plan? Given the one in five recurrence interval and eighteen multi-peaks, where does EGD's plan rank on the conservative/less aggressive spectrum, and why?
- (b) Does the recurrence interval determine the number of multi-peaks, and how, or are the two assumptions independent? Please explain and relate to the risk table on Figure 3 at p10.
- (c) Please show the illustrative impacts on a gas plan with one in ten recurrence interval.

RESPONSE

(a) Recurrence interval is defined as the average frequency in years with which actual peak day degree day values are likely to equal or exceed the design degree day value. Longer recurrence intervals provide a more conservative gas supply plan because longer recurrence intervals are associated with lower probability events occurring (the lower the probability of an event occurring, in this case degree days, the higher the degree day value associated with that lower probability).

To illustrate, the CDA's approved design criteria assumes a recurrence interval of 1-in-5, which corresponds to 41.4 degree days. In other words, there is a 20% chance each year of actual peak day degree days being equal to or exceeding 41.4 degree days. If the assumed recurrence interval was lengthened to 1-in-10, the CDA's design degree day assumption would increase to 43.7 degree days. Or, there would be a 10% chance each year of peak day degree days being equal to or exceeding 43.7 degree days.

Recognizing that as degree days increase so does demand, the development of a gas supply plan for a longer recurrence interval would result in the utility acquiring

Witness: D. Small

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¹ EB-2011-0354, Exhibit N1, Tab 1, Schedule 1, page 22

² EB-2011-0354, Exhibit D2, Tab 4, Schedule 2, page 25

Exhibit I.D1.EGDI.BOMA.18

Page 2 of 3

incremental upstream assets to meet the higher peak day demand associated with the higher degree days at a longer recurrence interval.

The Company's last evaluation of its design criteria riskiness was conducted by Navigant Consulting, through the use of a survey of similar utilities, and can be found at EB-2011-0354, Exhibit D2, Tab 3, Schedule 2.

When discussing the length of recurrence intervals to EGD's peers. Navigant found:

"no utility had a design day interval shorter than 10 years."

Navigant continues:

No respondent used a recurrence interval as short as EGD's current interval of five years. This may suggest that EGD's interval may be riskier than advisable. However, the interval should not be considered in isolation but conjointly with other factors (e.g., whether the other LDCs used the same range of weather data and whether they used Monte Carlo techniques) to determine the appropriate level of conservatism. As noted in the main body of this report, Monte Carlo analysis is inherently conservative, as it broadens the distribution of possible values for HDDs and wind speed.

Navigant's comments related to the use of single-peak vs using multi-peaks:

EGD currently has a multi-day design, although the days are not contiguous. The multi-day design is a conservative assumption that allows EGD to calculate a storage inventory reserve for its peak usage months. The temperature data calculated by Navigant can be used to support this approach. Ten respondents indicated that their design day criteria require them to retain a certain level of storage gas until a certain date.

- (b) The recurrence interval does not determine the number of multi-peaks. The assumed number of multi-peaks and the assumed length of the recurrence interval are assumptions which are independent of one another.
- (c) The main impact a 1 in 10 recurrence interval would have on the utility's gas supply plan would be to increase design degree days, which would increase franchise peak day demand.

Specifically, a 1 in 10 recurrence interval would increase peak day demand for the CDA by 175 TJ and 45 TJ for the EDA, or 220 TJ for the franchise. Assuming a 1 in10 recurrence interval would change the utility's 2018 peak day supply/demand balance from 0 TJ to (220) TJ. To eliminate the (220) TJ peak day deficiency, the utility would

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.18

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need to acquire 175 TJ/d of upstream assets with delivery to the CDA and 45 TJ/d of upstream assets with delivery to the EDA.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.19

Page 1 of 1
Plus Attachment

BOMA INTERROGATORY #19

INTERROGATORY

Ref: Ibid, p18

- (a) Please provide the amount of storage that EGD leases in Michigan, the owner of the facility, and the transportation it holds on pipelines in Michigan to move the gas to Ontario. At what point(s) does that gas enter Ontario, and by what route(s) does it reach Dawn?
- (b) Please provide a breakdown of the 24.4 PJs storage at market based prices that EGD has. How much of that is Union Gas? What other storage provider does EGD contract with, other than Union and the owner of the Michigan storage facility? When Union and EGD merge, will the existing Union storage be treated as EGD's own storage and available at cost based rates, or the lower of cost based or market based rates?

RESPONSE

- a) A similar question was asked and answered in EB-2016-0215 see BOMA Interrogatory #15 at Exhibit I.D1.EGDI.BOMA.15 attached.
- b) As discussed in the attached response from the 2017 Rate Adjustment Application, the Company is reluctant to provide contractual pricing information related to its market-based storage arrangements. The Company did however, provide as part of Exhibit D1, Tab 2, Schedule 9, page 2 of 2 a breakdown of whether or not the market-based storage arrangements were underpinned by physical storage or by synthetic storage. Questions about what may occur following the proposed amalgamation of EGD and Union on January 1, 2019 have no impact on the 2018 application.

Filed: 2017-11-13, EB-2017-0086, Exhibit I.D1.EGDI.BOMA.19, Attachment, Page 1 of 2

Filed: 2016-11-11 EB-2016-0215

Exhibit I.D1.EGDI.BOMA.15

Page 1 of 2

BOMA INTERROGATORY #15

<u>INTERROGATORY</u>

Ref: Ibid, Page 17

- (a) How much Michigan storage does EGD hold, with what company(ies)?
- (b) Please explain how that gas is transported to the EGD service area, or to Tecumseh storage from the Michigan sites.
- (c) Has EGD utilized, transported to the franchise, any of the Michigan gas?
- (d) Is the availability of the gas in storage in Michigan "equally available" as gas stored at Union or Tecumseh, or are there deliverability or transportation constraints? Please compare "deliverability ratios" in Michigan storage to Tecumseh and Union ratios.
- (e) In general, are the market prices charged by Michigan storage providers higher or lower than those charged by Union Gas? Do they include transport to Dawn/Tecumseh, or must transport be acquired separately?

<u>RESPONSE</u>

a) Enbridge currently has a contract with a storage provider located in Michigan. The Company is reluctant to provide the contract particulars as disclosing such information may create an impediment when the Company goes out into the marketplace to replace that storage contract upon expiry.

In response to BOMA # 17 at Exhibit I.D1.EGDI.BOMA.17, the Company has provided a copy of the RFP that was issued this fall for storage service commencing April1, 2017. As shown on that RFP, the Company would entertain proposals whereby Enbridge would provide volumes at Dawn and receive volumes at Dawn.

b) and c)

The Company does not hold transportation capacity to and from storage facilities in Michigan. The nature of the Company's contract for storage in Michigan is such that the storage entity receives gas from Enbridge at Dawn during the summer injection period and delivers gas to Enbridge at Dawn during the winter withdrawal period.

Filed: 2017-11-13, EB-2017-0086, Exhibit I.D1.EGDI.BOMA.19, Attachment, Page 2 of 2

Filed: 2016-11-11 EB-2016-0215

Exhibit I.D1.EGDI.BOMA.15

Page 2 of 2

Therefore, physical transportation forms part of this particular storage service and the Company does not contract for transportation capacity directly to move gas to/from storage in Michigan.

d) and e)

The Company has structured its third party storage contracts such that Enbridge will be entering the market place every year to replace a level of storage and by doing so can take advantage of updated market pricing and deliverability requirements.

As discussed in the response to part a) of this interrogatory, the Company is reluctant to provide information related to the prices charged on its various storage contracts.

As discussed in the response to parts b) and c) of this interrogatory, transport to Dawn/Tecumseh is not required due to the nature of the storage contract in question.

Filed: 2017-11-13 EB-2017-0086

Exhibit I.D1.EGDI.BOMA.20

Page 1 of 2

BOMA INTERROGATORY #20

INTERROGATORY

Ref: Ibid, p18

Please explain the need for additional discretionary requirements (purchase) during the winter to ensure that maximum deliverability from storage would be maintained until the end of February, and such that deliverability from storage would be sufficient to meet a March peak day as late as March 31st. How much additional winter discretionary purchase needs to be made and when would this purchase normally be made? Does EGD have an alternative to purchase additional storage capacity and deliverability instead, or is there no further storage capacity available? Please explain the interrelationship of the two commitments in more detail, perhaps with a numerical example. Did EGD have to purchase additional storage capacity, or deliverability, to implement the revised storage plan? Did it have increased pipeline capacity from Dawn? Please explain.

RESPONSE

Throughout the year, the daily demand of EGD's customers will be met by a gas supply portfolio of natural gas supply, transportation, and storage assets. Deliverability from storage on any given day is predicated on the storage balance on that day. Once storage balances decline beyond a certain point, the daily storage deliverability will decline. In order to maintain the maximum deliverability from storage as late into the winter season as possible it is necessary to maintain a physical balance that will guarantee the maximum deliverability. Therefore, if the Company wishes to maintain that balance in storage and still satisfy the needs of its customers it will need to acquire additional supplies. EGD first implemented a change in its Gas Supply Plan with respect to the management of its storage balances as part of its 2015 Gas Supply Plan (see EB-2014-0276).

As described at Exhibit D1, Tab 2, Schedule 3, page 7 of 15, paragraph 21, the Company is forecasting to acquire 58.9 Bcf of Dawn supplies throughout the winter in its 2018 Gas Supply Plan and intends to manage the acquisition of those supplies through an RFP process for a combination of seasonal, term and monthly supplies as well as buying gas on the day throughout the winter.

EGD plans to issue an RFP for storage capacity prior to the end of 2017. This is consistent with prior years to replace expiring storage capacity. The purpose of the RFP this year will be to replace the contracted storage capacity that is expiring March 31, 2018 and April 30, 2018 (3.1 PJ's and 2.1 PJ's respectively) as well as to contract for an incremental 2 to 3 PJ's of capacity. The Company believes that acquiring additional

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.20 Page 2 of 2

storage capacity will allow it to reduce the amount of Dawn supplies to be acquired in the winter of 2018 / 19.

The Company will not require incremental transportation capacity as a result of its intention to acquire additional storage capacity.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.21

Page 1 of 1

BOMA INTERROGATORY #21

INTERROGATORY

Ref: Ibid, p18

Please provide examples of "hybrid services" combining aspects of physical and synthetic storage. Please explain how each one works to provide enhanced operational flexibility to the company.

RESPONSE

The section of the evidence that refers to "hybrid services" is as follows:

Other gas supply arrangements with a counter party can have service attributes that are a hybrid of supply exchanges and peaking supplies. These hybrid services can offer enhanced operational flexibility to the Company. (emphasis added)

For a discussion about the "hybrid services", please see response to FRPO Interrogatory #10, at Exhibit ID1.EGDI.FRPO.10.

Filed: 2017-11-13 EB-2017-0086

Exhibit I.D1.EGDI.BOMA.22

Page 1 of 2 Plus Attachment

BOMA INTERROGATORY #22

INTERROGATORY

Ref: Ibid, p19

- (a) How many unbundled large industrial customers does EGD have? Is the option restricted to large industrials? While not in the gas supply plan, would EGD not be expected to backstop? Please confirm that EGD has no legal obligation to do so. Does it have a backstop rate?
- (b) Has EGD had to provide this "emergency service" in the past? If so, how many times? Please discuss.
- (c) Please describe the nature of the load balancing service that EGD supplies to OTS customers. Can you provide a contractual template for the service?

RESPONSE

a) EGD has five (5) unbundled distribution service customers. The unbundled distribution service options (Rate 125 and Rate 300) are available to any customers who qualify for the service as per the applicability requirements set out for each service in the Rate Handbook. EGD provides limited daily load balancing service to unbundled distribution service customers, which provides load balancing up to 60% of the customer's Contract Demand ("CD"). EGD's only obligation is to provide limited load balancing service to its unbundled distribution service customers as per the provisions of Rate 125 and Rate 300.

Note that unbundled distribution service customers are not obligated to provide Mean Daily Volume ("MDV") each and every day to the Company, but rather have to nominate daily and deliver daily the amount of gas required to serve the customer's daily load at the plant. If the unbundled customer's daily gas delivery does not match the customer's actual daily load / consumption at the plant, then EGD will provide limited load balancing up to 60% of the customer's CD for that day.

EGD can provide backstopping service under Rate 320 to bundled direct purchase customers to supply their MDV obligation (i.e., backstopping service applies in situations where direct purchase customers, either by themselves or through their marketers or brokers, cannot deliver their MDV obligation to the Company). In such situations, the Company can provide backstopping service up to the volume of gas available / allocated for backstopping in any day and supply the MDV obligation on

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.BOMA.22 Page 2 of 2 Plus Attachment

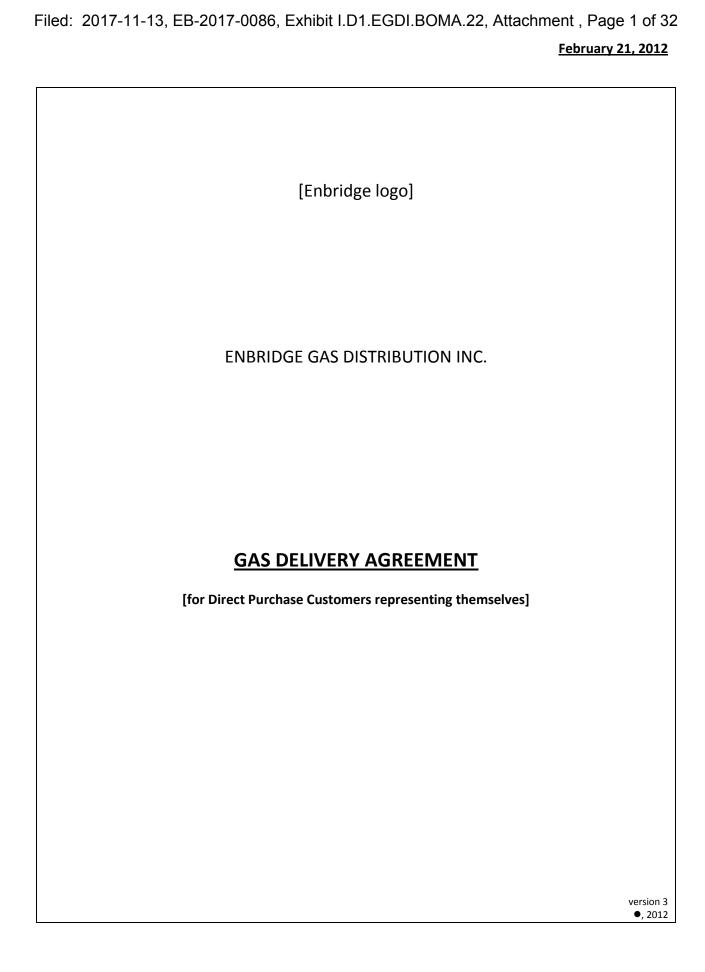
behalf of those direct purchase customers whose MDV supplies were not delivered to the Company).

- b) As described in part a) above, EGD does not provide backstopping service to its unbundled distribution service customers. EGD's only obligation is to provide limited load balancing service to its unbundled distribution service customers as per the provisions of Rate 125 and Rate 300.
- c) EGD provides / meets all of seasonal and daily load balancing needs of its Sales Service (i.e., System Gas), Western Transportation Service ("WTS"), Ontario Transportation Service (OTS) and Dawn Transportation Service (DTS) customers.

Note that direct purchase bundled customers ("WTS, OTS and DTS") also need to manage their Banked Gas Account ("BGA") balances, where BGA tracks the difference between the amount of gas delivered by the customer to the Company and the amount of gas used / consumed by the customer.

The Company provides a number of options / tools to direct purchase customers to manage (i.e., reduce or eliminate) their BGA balances such as make-ups, suspensions and title transfers.

Also, as requested within this question, attached is a copy of the Gas Delivery Agreement.



GAS DELIVERY AGREEMENT

THIS GAS DELIVERY AGREEMENT is made and entered into as of the <> day of <> , 20<>

BETWEEN:

ENBRIDGE GAS DISTRIBUTION INC.,

a corporation subsisting under the laws of Ontario

(the "Company")

- and -

, a corporation incorporated under the laws of [Ontario]

(the "Customer")

BACKGROUND

- A. This Agreement provides for the delivery of Gas by the Customer to the Company and for the redelivery of that Gas by the Company to the Customer.
- B. The Parties confirm that in addition to entering into this Agreement they have entered into one or more of the Enbridge Agreements.

THEREFORE IN CONSIDERATION of the foregoing premises and the mutual covenants and agreements contained in this Agreement and subject to the terms and conditions hereinafter set forth, the Parties agree as follows:

ARTICLE 1 INTERPRETATION

1.1 <u>Definitions</u>

In addition to any terms or phrases defined elsewhere in this Agreement, unless the context otherwise specifies or requires, for the purposes of this Agreement (including the Schedules hereto) capitalized terms used in this Agreement shall have the respective meanings attributed to them as follows:

"Agreement", "hereto", "hereof", "herein", "hereby", "hereunder", and similar expressions refer to this Gas Delivery Agreement, together with all attachments hereto, as the same may be amended or updated from time to time.

"Applicable Laws" means any and all applicable laws, statutes, by-laws, rules, regulations, orders and ordinances together with all codes, guidelines, policies, notices, directions, directives and standards of any Governmental Authority which are legally mandatory in nature, affecting the obligations of either of the Parties, from time to time.

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"Banked Gas Account" has the meaning given to such term in Section 3.1 of this Agreement.

"Business Day" means any day on which the Company's head office in Ontario is open for business as usual.

"Change Notice" has the meaning given to such term in Section 2.7.2 of this Agreement.

"Claim" means any claim, demand, liability, damage, loss, suit, dispute, civil or criminal litigation, action or cause of action, arbitration, or legal, administrative or other proceeding or governmental investigation, including appeals and applications for review and all costs and expenses relating thereto.

"Default" means an event or condition (including an act or omission), the occurrence of which would, with the lapse of time or the giving of notice, or both, become an Event of Default.

"Enbridge Agreements" means the Company's EnTRAC user agreement, collection services agreement, large volume distribution contract and GDAR services agreement, in each case as may be entered into between the Parties (as applicable) and any other agreement entered into between the Parties in connection with the foregoing agreements or this Agreement, in each case, as amended, restated, supplemented, revised or otherwise modified from time to time.

"Event of Default" has the meaning given to such term in Section 9.4 of this Agreement.

"Fuel Gas" means in respect of any Gas to be delivered by a Customer to the Company, the fuel ratio (expressed as a percentage of the volume of such gas) in effect from time to time for Gas transportation service, as established by the relevant Gas Transporter.

"Gas" means natural gas and/or residue gas comprised primarily of methane.

"Gas Transporter" means a Person, other than the Company, with which the Company or the Customer has contracted to transport Gas from or to any Point of Acceptance.

"Governmental Authority" means any government, regulatory body or authority, agency, crown corporation, governmental department, board, commission, tribunal, court or other law, rule, or regulation making authority having or purporting to have jurisdiction or control on behalf of Canada or any provincial, regional or local governmental, or other subdivision thereof, whether over the Parties, their facilities, any Gas supply, the sale, purchase or transportation of Gas, or this Agreement or any part hereof.

"MDV" means mean daily volume, as a reference to a volume of Gas, determined in accordance with the *Transaction Rules*.

"Nomination" has the meaning given to such term in Section 2.4.1 of this Agreement.

"OEB" means the Ontario Energy Board, or any successor regulatory entity.

"Party" means any one of the Company or the Customer, and "Parties" means both of them.

"Person" means an individual, corporation, partnership, firm, joint venture, syndicate, association, trust, trustee, government, governmental agency, board, tribunal, ministry, commission or department or

Gas Delivery Agreement - Customer Page 3 of 29

other form of entity or organization and the heirs, beneficiaries, executors, legal representatives or administrators of an individual, and "**Persons**" has a similar meaning.

"Personal Information" means any information that identifies or is associated with an individual and any other information considered to be personal information and which is protected or falls under the purview of applicable privacy legislation.

"Point of Acceptance" means a point at which the Company accepts delivery of a supply of Gas from, or in respect of, a Customer pursuant to this Agreement; and for certainty, shall be such location or locations as are established as valid points of receipt of Gas by the relevant Gas Transporter(s), and in each case as selected and identified in a Transaction Request during the submission of a Nomination for the relevant Pool; and for these purposes, will be either (i) an 'Ontario Point of Acceptance' (where acceptance of Gas by the Company's delivery area), or (ii) a 'Western Point of Acceptance' (where acceptance of Gas by the Company's delivery area).

"**Pool**" means a pool which has been established by the Customer for the purpose of the delivery of Gas by the Customer to the Company and the redelivery of that Gas by the Company to the Customer for a period of time, and has attached to it an identifier, start and end dates, a Point of Acceptance, one or more Terminal Location and an aggregate MDV.

"Rate Handbook" means the Company's 'Handbook of Rates and Distribution Services' as amended, updated or replaced by the Company from time to time with approval from the OEB.

"Rate Number" means a numbered rate established by the Company from time to time for one or more category of customer as approved by the OEB and in effect at the relevant time.

"Rate Schedule" means the schedule of rates, charges, terms and conditions associated with each Rate Number established by the Company from time to time as approved by the OEB and in effect at the relevant time.

"Required Orders" means such grants, permits, licences, registrations, approvals, consents, waivers, variances, exemptions, filings, authorizations, orders and decisions or requirements of or by any Governmental Authority having jurisdiction or control over any of the Parties or any provision hereof, as are from time to time necessary in order that the Agreement and the performance thereof by the Parties be in compliance with all Applicable Laws.

"System Gas" means commodity supply Gas provided by the Company pursuant to a Rate Number approved by the OEB.

"Terminal Location" means the building, plant or other facility of a Customer at or in which Gas to be delivered pursuant to this Agreement will be used by such Customer.

"Transaction Request" means a request from a Customer, which has been approved or accepted by the Company, for the provision of Gas delivery services offered by the Company pursuant to this Agreement and made by the Customer to the Company by any means, including any electronic instructions, which request shall be in the form and shall include such information as may be required by the Company pursuant to the *Transaction Rules*.

"Transaction Rules" means the rules, regulations, policies and procedures established by the Company, and amended or updated by the Company from time to time, in respect of the services provided pursuant to this Agreement, among others.

1.2 Rules of Interpretation

In this Agreement the following rules shall apply to the interpretation thereof:

- (a) words denoting the singular include the plural and vice versa and words denoting any gender include all genders;
- (b) the words "include", "includes" and "including" and other similar words and expressions shall in all cases be deemed to be followed by the words "without limitation";
- (c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;
- (d) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded;
- (e) unless otherwise specifically noted herein, all dollar amounts are expressed in Canadian currency;
- (f) the division of this Agreement into separate Articles, Sections, subsections and Schedules and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement; and
- (g) except as otherwise specifically defined or provided for in this Agreement, words or abbreviations which have well known or trade meanings are used in accordance with their recognized meanings.

1.3 <u>Entire Agreement</u>

This Agreement and all Exhibits, attachments, and addenda contemplated herein or specifically referred to herein constitute the entire agreement among the Parties pertaining to all the matters herein, and supersede all prior agreements, understandings, negotiations, discussions and other communications, whether oral or written, of the Parties.

1.4 Severability

This Agreement is a general form, intended for use by the Parties in their ongoing relations in Canada. If any provision of this Agreement or portion thereof or the application thereof to any Person or circumstance shall to any extent be invalid or unenforceable or contravene any Applicable Laws, then (a) the remainder of this Agreement or the application of such provision or portion thereof to any other Party or circumstance shall not be affected thereby, and (b) the Parties will negotiate in good

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faith to amend this Agreement to implement the intentions set forth herein. Each provision of this Agreement shall be valid and enforceable to the fullest extent permitted by law.

1.5 Applicable Law

This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and shall be treated as an Ontario contract. For the purpose of any legal actions or proceedings brought by any Party in respect of this Agreement, each Party irrevocably submits and attorns to the non-exclusive jurisdiction of the courts of the Province of Ontario.

1.6 Handbook

Parts III and IV of the Rate Handbook are incorporated into this Agreement and form a part hereof. Parts III and IV of the Rate Handbook shall be construed using the definitions contained in this Agreement and the terms used therein and not defined in this Agreement shall be construed using the definitions in Part I of the Rate Handbook. For certainty, for purposes of this Agreement, the term "Applicant" as referenced in the Rate Handbook shall mean "Customer" in this Agreement. If there is any conflict between the provisions of this Agreement and the provisions of the Rate Handbook, then the provisions of the Rate Handbook shall prevail.

1.7 Schedules

The Schedules set out below are required to complete this Agreement and are incorporated herein by reference and are deemed to be a part hereof and are to be read in conjunction with and subject to this Agreement.

Schedule "A" - Terms of Assignment of Company Capacity

1.8 <u>Substitution of Agreement</u>

If, and to the extent that, the Company and the Customer have prior to the date hereof entered into a gas delivery agreement similar to this Agreement (the "Prior Agreement") for or in respect of the delivery of Gas by the Customer to the Company and for the redelivery of that Gas by the Company to the Customer, the Prior Agreement is hereby amended and restated effective as of the coming into force of this Agreement, and thereafter replaced by this Agreement. For certainty, the execution and delivery of this Agreement shall not affect any action taken, gas deliveries or payments made under or pursuant to, or in reliance on the Prior Agreement, including the establishment of any Pool thereunder, each of which shall continue to exist and shall hereafter be subject to the terms and conditions of this Agreement.

ARTICLE 2 BASIC AGREEMENTS

2.1 Receipt and Delivery of Gas

2.1.1 Receipt - On and subject to the terms of this Agreement, during the Term the Company shall receive Gas from the Customer and the Customer shall deliver Gas to the Company.

- 2.1.2 <u>Point of Acceptance</u> All Gas delivered to the Company by the Customer pursuant to this Agreement shall be delivered at one or more Point of Acceptance, as selected and identified in a Transaction Request, in accordance with the *Transaction Rules*.
- 2.1.3 <u>Delivery</u> On and subject to the terms of this Agreement, during the Term the Company shall deliver Gas to the Customer, at the rates referred to herein.
- 2.1.4 <u>Delivery at Terminal Location</u> All Gas delivered to a Customer by the Company pursuant to this Agreement shall be delivered at the outlet of the Company's metering equipment at each Terminal Location, as selected and identified in a Transaction Request, in accordance with the *Transaction Rules*.

2.2 <u>Volumes</u>

- 2.2.1 <u>Contracted Pool MDV</u> The contracted Pool MDV is the aggregate volume of expected deliveries of Gas (excluding Fuel Gas) to be made by the Customer in respect of a Pool calculated in accordance with the *Transaction Rules*. The Customer shall deliver the contracted MDV on each day of the term of the relevant Pool.
- 2.2.2 <u>Updated Pool MDV</u> The contracted Pool MDV shall be automatically updated in the manner and to the extent set out in the *Transaction Rules*. Such updated MDV shall thereafter constitute the contracted Pool MDV for such Pool.
- 2.2.3 <u>Maximum Daily Receipt</u> The maximum volume of Gas the Company is required to receive from the Customer in respect of a Pool in any day is the aggregate of: (A) the contracted Pool MDV; and (B) the volume of Gas in excess of the Gas referred to in <u>Section 2.2.1</u> which the Customer is to deliver to the Company on such day pursuant to one or more Transaction Requests, in connection with the balancing of actual volumes of Gas previously received, or to have been received, from the Customer against the volumes of Gas consumed by the Customer; and in any hour is one-twentieth (1/20th) of such amount.
- 2.2.4 <u>No Transfer of Volumes</u> The accounting between the Customer and the Company for Gas received by the Company from the Customer in respect of a Pool will be on a daily basis with no right in any Party to transfer any Gas as between the days during which the relevant Pool is in effect. For certainty, if the Customer is deficient in the delivery of the contracted Pool MDV or any day during the term of a Pool, it cannot make-up that deficiency on another day.
- 2.2.5 <u>Fuel Gas</u> The Customer shall, on a daily basis, provide the necessary Fuel Gas based on the relevant Gas Transporter's published monthly fuel ratio for the corresponding Point of Acceptance, when applicable.

2.3 Rates

- 2.3.1 <u>Applicable Rates</u> Subject to the other terms and conditions of this Agreement, the rates and charges for delivery of Gas to a Customer hereunder in respect of any Terminal Location shall be the Rate Number associated with the Customer and the corresponding Rate Schedule.
- 2.3.2 <u>Independence of Rates</u> The rates and charges applicable to the delivery of Gas to a Terminal Location of the Customer shall be determined and computed in accordance with the relevant

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Rate Schedule without regard to any volume of Gas contracted to be delivered, or delivered, to any other Terminal Location or under any other Rate Schedule or pursuant to any other agreement to which the Company and the Customer are parties.

2.4 <u>Nominations</u>

- 2.4.1 <u>Nominations</u> In respect of each Pool, the Customer may, from time to time during the contract term of the Pool, provide to the Company a Transaction Request specifying, among other things, details of the volumes (including the contracted Pool MDV during the relevant periods for such Pool), as well as the relevant Point of Acceptance of the Gas included in such Pool (each, a "Nomination"). All Nominations shall be made in accordance with the *Transaction Rules*.
- 2.4.2 <u>Effective Time of Nomination</u> Each Nomination shall only be effective from and after the time and date established by the relevant Transaction Request.
- 2.4.3 <u>Failure to Submit Initial Nomination</u> If a valid Nomination is not submitted in respect of a Pool prior to any Gas in respect of such Pool beginning to flow, then the Company shall have no obligation to accept deliveries of Gas at the Point of Acceptance, in respect of such Pool.

2.5 <u>Assignment of Company Capacity</u>

- 2.5.1 Request for Assignment If (1) a Pool is established with an Ontario Point of Acceptance, (2) the Customer requests the Company assign part of the Company's service entitlement as shipper under the Company's contract with a Gas Transporter, and (3) the Company agrees to make such assignment and the Customer and the Company agree on the volume of Gas to be subject to such assignment, then the terms and conditions of Schedule "A" Terms of Assignment of Company Capacity shall apply to the Company and the Customer in respect of such Pool.
- 2.5.2 <u>Temporary Assignment</u> If (1) a Pool is established with a Western Point of Acceptance, and (2) the Customer requests the Company suspend certain Gas deliveries, then (3) the Company shall use reasonable efforts to make available a part of the Company's service entitlement as shipper under the Company's contract with the relevant Gas Transporter in accordance with the *Transaction Rules*, and (4) the terms and conditions of <u>Schedule "A" Terms of Assignment of Company Capacity</u> shall apply to the Company and the Customer, in respect of such suspension.

2.6 <u>Priority of Service and Curtailment</u>

2.6.1 Contingency Curtailment - In the event of actual or threatened inability to deliver the volume(s) of Gas contracted for under this Agreement to a Terminal Location due to an Event of Force Majeure affecting the Company, or when curtailment or discontinuance of supply is ordered by an authorized Governmental Authority, the Customer shall, at the direction of the Company, curtail or discontinue use of Gas during the period specified by the Company (by notice to the Customer in accordance with the other terms of this Agreement) so as to safeguard the health and safety of the public. If the Company intends to require a Customer to curtail or discontinue use of Gas pursuant to this Section 2.6.1 as a result of a threatened inability to deliver due to an Event of Force Majeure affecting the Company, then as soon as the Company makes the determination that there is a threatened inability to deliver (which determination will be made in the Company's sole discretion acting reasonably) the Company will notify the Customer of the determination and the reasons therefor. If the curtailment or discontinuance of supply is ordered by an authorized Governmental Authority, then

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the Company shall ensure that the notice to the Customer to curtail or discontinue use is consistent with such order, and that the duration of such curtailment or discontinuance is not longer than that required in such order. Any curtailment or discontinuance shall be effected by the Company in a manner consistent with the then current policy of the Company regarding curtailment or discontinuance of use. The Company shall not be liable for any loss of production or for any damages whatsoever by reason of any such curtailment or discontinuance or because of the length of advance notice given directing such curtailment or discontinuance.

Maintenance Curtailment - The Company may be required from time to time to perform maintenance or construction to its facilities which may impact the Company's ability to meet the Customers' requirements, or the Company's obligations, set out in this Agreement. In such event, except in cases of emergency, the Company shall provide the Customer with reasonable notice of the suspension of service (in light of the circumstances relating to the suspension) in accordance with the other terms of this Agreement. For certainty, in cases of emergency no prior notice or consultation by the Company shall be required to perform any required maintenance or construction, provided the Company shall use reasonable efforts to inform the Customer of the nature, extent and timing of such emergency. In all cases, the Company shall use reasonable efforts to limit the extent and duration of any service interruption hereunder.

2.7 Transaction Rules

- 2.7.1 <u>Compliance</u> The Customer acknowledges and agrees: (A) that it shall at all times conduct its business relations with the Company in strict compliance with the terms and conditions of this Agreement, including the *Transaction Rules*, as amended from time to time; and (B) that all of such terms and conditions, as amended from time to time, shall be applicable to and binding upon the Customer. The Company acknowledges and agrees that it shall at all times conduct its business relations with the Customer in strict compliance with the terms and conditions of this Agreement, including the *Transaction Rules*, as amended from time to time. If there is any conflict between the provisions of this Agreement and the provisions of the *Transaction Rules*, the provisions of this Agreement shall prevail.
- 2.7.2 <u>Changes</u> The Company may, at any time and from time to time, in its sole discretion acting reasonably and in the interests of maintaining the integrity of the Company's Gas distribution system, make changes to the *Transaction Rules*. All such changes shall become effective on the first day of the month which is not less than thirty-five (35) days following notification to the Customer of the relevant change (the "**Change Notice**"). The Change Notice shall include a brief description of the background to and rationale for each change. To the extent that the Company is able, in it sole discretion, to provide additional notice to the Customer of any proposed changes, in advance of the delivery of the Change Notice, the Company shall endeavour to do so.
- 2.7.3 <u>Effect of Changes</u> On the effective date set out in the Change Notice, the change or changes set out therein shall be deemed to be, and shall be and become, a part of this Agreement. The Customer covenants and agrees to comply with such change or changes forthwith thereafter.

2.8 No Agency

2.8.1 <u>Representations and Warranties</u> - In addition to any other representations and warranties given to the Company under this Agreement, the Customer represents and warrants to the Company, and acknowledges and agrees that the Company is relying on the accuracy of each of such

representations and warranties in entering into this Agreement, that at the date hereof and at all times during the Term:

- (a) the Customer is not and will not be acting, or purporting to act, as agent of any other Person with respect to any of the gas delivery services of the Company under this Agreement; and
- (b) the Customer is and will be the direct or indirect owner of, or has and will have direct or indirect control over, each of the Terminal Locations which is or will be the subject of a Transaction Request pursuant to this Agreement.
- 2.8.2 <u>Proof of Status</u> The Company shall have the right, at any time and from time to time, without in any way limiting the foregoing representations and warranties of the Customer, to require the Customer to provide the Company proof, which must be satisfactory to the Company in its sole discretion, acting reasonably, that the Company has the status contemplated in Section 2.8.1.

ARTICLE 3 VOLUMETRICS

3.1 Banked Gas Accounts

The volume of Gas delivered by or for the Customer to the Point of Acceptance on each day of the term of the relevant Pool is referred to as the "Gas Delivered", and the volume of Gas delivered by the Company to the Terminal Location of the Customer on such day is referred to as the "Gas Taken"). The Customer acknowledges and agrees that there shall be established for each Pool an account to record the volumes of Gas Delivered and Gas Taken in respect of such Pool (each, a "Banked Gas Account"), and that the receipt and delivery information, regardless of the number or location of Terminal Location(s) associated with such Pool shall be aggregated for the purposes of determining the balance of the Banked Gas Account of such Pool.

3.2 Banked Gas Balancing

- 3.2.1 <u>During the Term of Pool</u> During the term of a Pool, in order to attempt to balance the actual aggregate volumes of Gas Delivered and Gas Taken in respect of a Pool, the Customer may take such steps and actions as are set out and provided for in the Rate Handbook and the *Transaction Rules*.
- 3.2.2 <u>Upon Expiry of Pool</u> Following the expiry of the term of a Pool, the Customer may, during the period and in the manner and to the extent set out in the relevant section(s) of the Rate Handbook, take such steps and actions to balance the actual aggregate volumes of Gas Delivered and Gas Taken in respect of such Pool as are set out in such section(s) in accordance with the *Transaction Rules*.

3.3 <u>Deficiency of Gas</u>

3.3.1 <u>Determination of Deficiency</u> – Following the expiry of the term of a Pool and on each anniversary date of such Pool, the Company will, and from time to time during the currency of the Pool, the Company may, prepare an accounting of Gas Delivered and Gas Taken. The amount by which the

Gas Taken in respect of such Pool exceeds the Gas Delivered in respect of such Pool is referred to as the "Deficiency".

- 3.3.2 <u>Responsibility for Deficiency</u> The Customer shall be responsible to reimburse the Company for any Deficiency. Such Deficiency shall be settled in a manner permitted by the Company and as set out in the Rate Handbook or the *Transaction Rules*.
- 3.3.3 Crystallization of Deficiency This Agreement and each of the Enbridge Agreements into which the Customer has entered with the Company are related documents and each forms an integral part of the others, and they are all closely connected. At any time, the Company may provide the Customer notice in writing advising the Customer of the liquidated sum owing in respect of the Deficiency at such time. Notwithstanding the previous sentence, whether or not the Company provides such a notice to the Customer, the Customer shall be deemed to be notified of the liquidated sum owing in respect of the Deficiency (A) automatically upon an Event of Default described in Subsections 9.4(c), 9.4(e) or 9.4(f), and (B) at such time as the Company provides the Customer with notice of its intention to do so upon an Event of Default described in Subsections 9.4(a) or 9.4(b). For purposes of this Agreement, the phrase 'liquidated sum owing in respect of the Deficiency' means the amount owing to the Company at the relevant time by the Customer, calculated as:
 - (a) the Deficiency, multiplied by
 - (b) either
 - (i) for Pools with a Western Point of Acceptance, one hundred twenty percent (120%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, or
 - (ii) for Pools with an Ontario Point of Acceptance, one hundred twenty percent (120%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to the Ontario Point of Acceptance over such contract year.

3.4 <u>Surplus of Gas</u>

- 3.4.1 <u>Determination of Surplus</u> In connection with the preparation by the Company of an accounting of Gas Delivered and Gas Taken as contemplated in <u>Section 3.3.1</u> in respect of a Pool, the amount by which the Gas Delivered in respect of such Pool exceeds the Gas Taken in respect of such Pool is referred to as the "**Surplus**".
- 3.4.2 <u>Deemed Trust</u> At all times the Surplus shall be held in trust by all of the Parties for the benefit of the Company for the purposes provided herein. To the extent there are any obligations owing by the Customer to the Company hereunder or under any Enbridge Agreement (collectively, the "**Obligations**"), then such amount of the Surplus (together with title thereto) necessary to offset the Obligations (such amount being based on the liquidated value of the Surplus determined in accordance with Section 3.4.3), shall be forthwith paid, transferred or delivered to the Company as contemplated in

<u>Section 7.7</u>, and the Customer shall be deemed to have irrevocably transferred such amount of the Surplus to the Company for such purpose. In addition, the Customer shall not be entitled to the Surplus nor be permitted to exercise any right of set-off it may now or hereafter have in respect of same until such time as the Obligations have been repaid or otherwise satisfied in full.

- 3.4.3 <u>Crystallization of Surplus</u> This Agreement and each of the Enbridge Agreements into which any of the Parties have entered with the Company are related documents and each forms an integral part of the others, and they are all closely connected. At any time, the Company may provide the Customer notice in writing advising the Customer of the liquidated value of the Surplus at such time. Notwithstanding the previous sentence, whether or not the Company provides such a notice to the Customer, the Customer shall be deemed to be notified of the liquidated value of the Surplus (A) automatically upon an Event of Default described in <u>Subsections 9.4(c)</u>, 9.4(e) or 9.4(f), and (B) at such time as the Company provides the Customer with notice of its intention to do so upon an Event of Default described in <u>Subsections 9.4(a) or 9.4(b)</u>. For purposes of this Agreement, the phrase 'liquidated value of the Surplus' means the then current value of the Surplus at the relevant time, calculated as:
 - (a) the Surplus, multiplied by
 - (b) either
 - (i) for Pools with a Western Point of Acceptance, eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to the Ontario Point of Acceptance over such contract year, or
 - (ii) for Pools with an Ontario Point of Acceptance, eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

3.5 <u>Additional Definition</u>

For certainty, the phrase "the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs" shall have the meaning commonly understood in the gas supply industry.

ARTICLE 4 DELIVERY, POSSESSION, TITLE AND COMMINGLING

4.1 <u>Possession</u>

The Customer shall be deemed to be in control and possession of, and responsible for, the relevant Gas that is the subject matter of each Pool (other than Gas purchased from the Company) until it shall have been delivered to or for the account of the Company at the Point of Acceptance, after which the Company shall be deemed to be in control and possession of, and responsible for, such Gas until it is delivered to the Terminal Location, after which the Customer shall be deemed to be in control

and possession of, and responsible for, such Gas. The Customer shall bear the full cost and expense for transporting and delivering such Gas to the Point of Acceptance.

4.2 <u>Delivery and Title</u>

- 4.2.1 <u>Under Consumption</u> The Gas Delivered shall be deemed to have been redelivered to the Terminal Location to the extent of the lesser of: (A) the Gas Delivered; and (B) the Gas Taken, and, subject to Section 3.4, title to that lesser amount of Gas shall at all times remain in the Customer.
- 4.2.2 Over Consumption If the Gas Taken exceeds the Gas Delivered, then title to such Gas Taken in excess of the Gas Delivered shall remain in the Company to, and pass from the Company to such Customer at, the Terminal Location.
- 4.2.3 <u>Title of Customer</u> Except as provided in <u>Section 3.4</u>, <u>Subsections 4.2.1</u> and <u>4.2.2</u> and <u>Section 7.7</u>, at any particular time the Customer shall have title to, and only to, Gas Delivered in excess of the Gas Taken during the term of the relevant Pool to the extent of the credit balance, if any, at such time in the Banked Gas Account of the relevant Pool.

4.3 Right to Commingle

The Company shall have the right to commingle Gas delivered to the Company by or for Customers at the Point of Acceptance with Gas owned by the Company or any other Person or Persons, and the Company shall have the right and full and absolute authority to deal in any manner with all Gas delivered to it, subject to the terms of this Agreement.

4.4 <u>Additional Representations and Warranties of the Customer</u>

In addition to any other representations and warranties given to the Company under this Agreement, the Customer represents and warrants to the Company that at the date hereof and at all times during the Term:

- (a) the Customer shall have good and marketable title in and to the Gas to be delivered to the Company and shall be entitled to deliver and, where applicable, sell such Gas to the Company in accordance with the terms of this Agreement, free and clear of any adverse claim of any nature or kind whatsoever; and
- (b) Gas delivered to the Company by or for the Customer will not be subject to any royalties, taxes (federal and/or provincial) or other charges payable by, or that may become a liability of, the Company and the purchases by the Company from the Customer contemplated hereby will not result in any liability to the Company for royalties, taxes (federal and/or provincial but not income taxes) or like charges which are applicable before possession of and title to such Gas passes to the Company,

and acknowledges and agrees that the Company is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement and the acceptance by the Company of all Nominations made by the Customer.

4.5 Representations and Warranties of the Company

The Company represents and warrants to the Customer that at the date hereof and at all times during the Term:

- (a) the Gas delivered to the Terminal Location shall conform to the minimum standards established by the Company for Gas in its distribution system; and
- (b) the Company shall not, and shall not take any action to cause any other Person to, create any lien, encumbrance or other adverse claim upon the Gas delivered by any Customer to the Company hereunder,

and acknowledges that the Customer is relying on the accuracy of each of such representations and warranties in connection with the entering into of this Agreement.

ARTICLE 5 POINT OF ACCEPTANCE - QUALITY AND MEASUREMENTS

5.1 Quality and Measurements

- 5.1.1 <u>Quality</u> The Customer acknowledges and agrees that the quality, pressure and temperature of the Gas delivered by the Customer hereunder shall conform to the minimum standards of the relevant Gas Transporter and such Gas shall otherwise be marketable Gas.
- 5.1.2 <u>Measurement</u> For the purpose of determining the volume of Gas delivered to the Company by the Customer, the Parties agree to accept the measurement of the relevant Gas Transporter(s), or as the Gas Transporter and the Company may otherwise agree, and the volume of Gas so determined for a particular day shall be deemed to be the volume of Gas delivered by such Customer to the Company on such day. The standard of measurement and tests for the Gas delivered hereunder shall be in accordance with the contractual arrangements made by the Company with the relevant Gas Transporter(s), or as the Gas Transporter and the Company may otherwise agree, in effect from time to time.
- 5.1.3 <u>Testing</u> In the event that either Party should request measuring or testing at any time, the other Party will cooperate fully to obtain such measurement and testing from the relevant Gas Transporter(s), provided that the Party seeking the test shall bear the cost thereof if the contractual arrangements of the Company with the relevant Gas Transporter(s) require payment of such cost.

ARTICLE 6 TERMINAL LOCATION - METERING AND EQUIPMENT

6.1 Metering at Point of Delivery

6.1.1 <u>Installation</u> - The Company agrees to install, operate and maintain measurement equipment of suitable capacity and design as is required to measure the volume of Gas to be delivered by the Company under this Agreement. The Customer agrees to provide, at its own expense, (i) any and all housing reasonably required by the Company for the protection of such measurement equipment and regulating equipment at the Customer's premises used in connection with the delivery of any such

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Gas, and (ii) if required for the Company's measurement equipment, a continuous supply of electrical power at 110 volts and a non-dedicated, single, voice grade, analog outside telephone line for local and WATTS (800 service) calls. The measurement and regulating equipment shall be installed at such location as the Company may determine, in its discretion acting reasonably; provided that if the Company determines that such equipment should be installed on the Customer's premises, the site shall be as agreed between the Customer and the Company; and provided further that all installations of equipment must be made in accordance with all applicable safety regulations.

6.1.2 Access - The Company and the Customer shall each have access to and the right to enter the measurement/regulating location at any reasonable time on prior notice to the Customer or the Company, as the case may be, and shall have the right to be present at the time of installing, reading, cleaning, changing, repairing, inspecting, testing, calibrating or adjusting of measurement equipment. Access under this Section is subject to the Party which is accessing the location complying with any specific policies or procedures in respect thereof that are provided to it by the Party permitting such access following the giving of the notice requiring such access.

6.2 Examination

- 6.2.1 If requested by a Customer, the Company's measurement equipment shall be examined by the Company in the presence of a representative of the Customer, but the Company shall not be required as a matter of routine to examine such equipment more frequently than as may be required by Applicable Laws.
- 6.2.2 If the measurement equipment is found to be in error by not more than three per cent (3%), the previous recording shall be considered correct but proper adjustments to or replacement of, as appropriate, the measurement equipment will be made immediately. However, if the error is greater than three per cent (3%), in addition to proper adjustments to or replacement of, as appropriate, the measurement equipment, a correction in billing shall be made in accordance with the *Electricity and Gas Inspection Act* and the Regulations made thereunder or any other legislation which may succeed the said Act.
- 6.2.3 Gas measurement equipment that malfunctions for whatever reason shall be dealt with in accordance with the foregoing subparagraph of this <u>Section 6.2</u>.

6.3 <u>Measurement Criteria</u>

- 6.3.1 All Gas delivered shall be measured utilizing equipment which conforms to the regulations prescribed in "Departmental Instructions for Inspection of Gas Meters and Auxiliary Devices" dated October 1976, issued by the Department of Customer & Corporate Affairs, Government of Canada, as amended from time to time.
- 6.3.2 The measurement unit shall be one cubic meter of Gas at a pressure of 101.325 kpa absolute and at a temperature of fifteen (15) degrees Celsius. The average absolute atmospheric (barometric) pressure shall be calculated in accordance with the *Electricity and Gas Inspection Act* and the Regulations made thereunder or any other legislation which may succeed the said Act, regardless of variations in actual barometric pressure from time to time.

6.4 <u>Equipment</u>

The title to all service pipes, meters, regulators, attachments and equipment placed on a Customer's premises and not sold to the Customer shall remain with the Company, with right of removal, and no charge shall be made by a Customer for use of premises occupied thereby.

ARTICLE 7 GENERAL RIGHTS AND OBLIGATIONS OF THE PARTIES

7.1 Early Termination of Pools

Right to Terminate a Pool - The Company shall have the right to terminate a Pool at any time prior to the expiry of the term of the Pool if: (A) the Customer fails to perform or observe any of its obligations under this Agreement on its part to be observed and performed; and (B) the obligation affects in any way the relevant Pool; and either (C) the failure shall continue unremedied following notice thereof (giving particulars of the failure in reasonable detail) from the Company to the Customer for a period of five (5) Business Days; or (D) the Company, in its sole discretion acting reasonably, shall determine that the failure: (i) may materially adversely affect the provision of any services by the Company to any other Customer; or (ii) may cause the Company to be in breach of any contractual obligation to any other customer of the Company; and (iii) in either event, cannot be cured in sufficient time.

7.1.2 <u>Effects of Termination of a Pool</u> - Upon the early termination of a Pool pursuant to Section 7.1.1:

- (a) the Customer: (A) shall revert to System Gas; and (B) may be transferred to another Pool if the Company has received an appropriate Transaction Request; and
- (b) the Company shall, as soon as reasonably practicable and in any event not later than ninety (90) days following termination of the relevant Pool, prepare and forward to the Customer a statement setting out the status of the Banked Gas Account for the Pool; and forthwith following receipt of such statement, the Customer shall settle such obligation in a manner permitted by the Company and as set out in the Rate Handbook or the *Transaction Rules*.
- 7.1.3 No Liability of Company Provided that the Company has acted in accordance with the material terms of this Agreement, the Company shall have no liability to the Customer or to any Person with whom, or for whom, the Customer has any contractual or other obligations as a result of the termination of the Pool pursuant to this <u>Section 7.1</u>.

7.2 <u>Governmental Regulations</u>

7.2.1 This Agreement is subject to (A) the maintenance of all Required Orders, and (B) all Applicable Laws.

- 7.2.2 Except as provided in <u>Section 7.2.4</u>, the Customer shall promptly endeavour to obtain or cause to be obtained all Required Orders. The Customer shall provide true copies of all Required Orders (other than those contemplated in Section 7.2.4) to the Company upon request.
- 7.2.3 The Customer shall comply with the terms of all Required Orders applicable to it and shall use its best efforts to maintain the same in full force and effect throughout the Term. The Company will comply with all Required Orders applicable to it and will use its best efforts to maintain the same in full force and effect throughout the Term.
- 7.2.4 The Company shall promptly endeavour to obtain or cause to be obtained all Required Orders as it relates to Gas to be dealt with under this Agreement after it is delivered to the Point of Acceptance until it is delivered to a Terminal Location.

7.3 Suspension of Company's Obligations

In addition to any other rights the Company may have, the Company shall not be required to perform its obligations hereunder, and shall be entitled to suspend such obligations, at any particular time if:

- (a) there is a breach or default of any representation, warranty or obligation of the Customer set out in this Agreement, as determined by the Company, in its sole discretion acting reasonably and where such breach or default affects the integrity of the Company's Gas distribution system;
- (b) any Required Order ceases to be in effect or if the Company has not received an original or true copy of any Required Order which has been requested by the Company; or
- (c) performance of any such obligation would be in contravention of any Applicable Law.

If the Company suspends any of its obligations pursuant to this Section, then it shall deliver a notice to that effect to the Customer and the reasons therefor. If a Suspension Period continues for more than thirty (30) consecutive days, then the Company may terminate this Agreement, or any one or more affected Pools, by notice to the relevant Customers given by the Company after the thirtieth (30th) day in such Suspension Period, and such termination shall be effective on the later of a date stipulated in such notice and the date on which such notice is received by the Customer. In this Section, "Suspension Period" means a period throughout which the Company is not required to perform its obligations hereunder as permitted by this Section.

7.4 <u>Adoption of NAESB Standards</u>

- 7.4.1 Acknowledgement of Standards Each of the Parties acknowledges and agrees that the North American Energy Standards Board ("NAESB") develops and promotes standards for business practices and electronic communication of Gas transactions, with a view to simplifying the management of Gas across the entire North American pipeline grid.
- 7.4.2 <u>Amendment to Conform with Standards</u> The Customer hereby acknowledges that the NAESB may, from time to time, revise or implement standards that conflict with or supplement the

provisions of this Agreement. If at any time the Company is required to adopt a recommended standard that conflicts with or supplements the provisions of this Agreement as a result of a Required Order or the imposition of such standards on the Company by any Gas Transporter which necessitates the Company adopting such standards, then the Company shall deliver a notice to the Customer which specifies such standards and sets out the revisions to this Agreement that are required to accommodate such standards. The Parties agree that on the thirtieth (30th) day following the delivery of such notice, or such earlier day that such standards are imposed on the Company, this Agreement shall be deemed to be amended by the incorporation of the revisions set out in such notice.

7.5 <u>Force Majeure</u>

7.5.1 Effect of Force Majeure - Subject to the other provisions of this Section 7.5, a Party shall not be liable to the other Party, in respect of such first mentioned Party's obligations under this Agreement, as a result of the inability of the first mentioned Party to deliver or receive Gas if such inability is caused by an event of Force Majeure. A delay or interruption in the performance by a Party of any of such obligations due to Force Majeure, shall suspend the period of performance of such obligation during the continuance of such Force Majeure.

7.5.2 <u>Notice and Other Requirements</u>

- (a) Initial Notice Forthwith following a Party becoming or being made aware of an Event of Force Majeure which may impact on any of such Party's obligations, such Party shall notify the other Party of the event and of the manner in which such Party's obligations hereunder will or may be affected; and such Event of Force Majeure shall be deemed to have commenced when it occurred provided notice is given within six (6) hours of the occurrence, and otherwise when such notice is given.
- (b) Efforts to Eliminate The Party claiming Force Majeure shall, unless such Event of Force Majeure is a strike, lockout or other industrial disturbance, use its best efforts to eliminate such event of Force Majeure.
- (c) Subsequent Notice The Party claiming Force Majeure shall forthwith give notice to the other Party when such Event of Force Majeure has been eliminated or has ceased to prevent the Party claiming Force Majeure from fulfilling its obligation to deliver or receive Gas as contemplated herein.
- (d) Recommencement of Obligations The Party claiming Force Majeure shall proceed to fulfill such Party's obligations which are impacted by the Event of Force Majeure as soon as reasonably possible after such Event of Force Majeure has been eliminated or has ceased to prevent the Party claiming Force Majeure from fulfilling such obligations.
- (e) Oral Notice Any notice under this <u>Section 7.5.2</u> may be given orally; provided that such notice shall only be effective if it is confirmed the same day in writing by facsimile or as otherwise provided in <u>Section 12.1</u>.

- 7.5.3 <u>Definition</u> In this Agreement, "**Force Majeure**" or "**Event of Force Majeure**" means any cause (A) not reasonably within the control of the Party claiming force majeure, and (B) which by exercise of due diligence such Party is unable to prevent or overcome, and includes the following:
 - (a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport Gas, the necessity of repairs to or alterations of such machinery or equipment or lines of pipe, or inability to obtain materials, supplies (including a supply of services) or permits required to perform a Party's obligations under this Agreement;
 - (b) interruption and/or curtailment of firm transportation by a Gas Transporter;
 - (c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections of war, as well as physical damage resulting from the negligence of others; and
 - (d) governmental actions, such as necessity for compliance with any Applicable Law.
- 7.5.4 Force Majeure Declared by Company In the event a Force Majeure is declared by the Company, the Customer will continue to be obligated for all applicable charges relevant to contracted services which continue to be available notwithstanding the Event of Force Majeure and may only be relieved of any applicable charges, if any, relevant to contracted services not available to the Customer as a direct result of the Force Majeure. Any related upstream transportation charges would be the Customer's sole responsibility.
- 7.5.5 Force Majeure Declared by Customer In the event the Force Majeure is declared by the Customer, all demand, commodity and service rates and charges in respect of currently effective Nominations or financial obligations otherwise payable under this Agreement will remain payable to the Company. If any Force Majeure occurs at the Customer's facilities downstream of the Company's metering equipment at the relevant Terminal Location, the Customer will remain obligated to, if applicable, deliver gas at the Point Acceptance in respect of the then currently effective Nominations.
- 7.5.6 Additional Effect of Force Majeure Except as provided in Section 7.5.8, and subject to Section 7.5.7, a Party hereunder shall not be liable to the other Party hereunder for the first mentioned Party's inability to deliver or receive gas as contemplated herein if such inability is caused by an Event of Force Majeure. In the case of any such inability so caused, then the other Party shall have no claim for damages or specific performance or other right of action against the first mentioned Party.
- 7.5.7 <u>Limitations</u> Notwithstanding any other term of this <u>Section 7.5</u>, no Party shall be entitled to, or to claim, the benefit of the provisions of Force Majeure to the extent performance is affected by any or all of the following circumstances:
 - (a) the curtailment of interruptible Gas supply;

- (b) a Force Majeure claimed by a Gas Transporter responsible for the delivery to the Point of Acceptance of Gas for which a Nomination has been accepted by the Company hereunder, if (i) another Gas Transporter is capable of delivering such Gas to the Point of Acceptance (unless the Party has used its best efforts to contract with such other Gas Transporter and has been unable to do so); or (ii) Gas is available in the secondary market from another supplier sufficient to meet the terms of the relevant Nomination;
- (c) economic hardship, including the Customer's ability to sell Gas at a higher or more advantageous price or to buy Gas at a lower or more advantageous price; or
- (d) the loss or failure of the Customer's Gas supply or depletion of reserves, unless (i) the Force Majeure causing such loss or failure is a result of a natural disaster (such as landslide, earthquake or hurricane) or an act of others (such as terrorism, riot, sabotage, insurrection or war; but not a strike, lockout or other industrial disturbance); and (ii) Gas is not available in the secondary market from another supplier sufficient to meet the terms of the Customer's then current obligations under this Agreement.
- 7.5.8 <u>Further Limitations</u> Notwithstanding any other term of this <u>Section 7.5</u>, no Party shall be entitled to, or to claim, the benefit of the provisions of Force Majeure if:
 - (a) such Party's inability to perform the obligation was caused by its lack of finances; or
 - (b) such Party's inability to perform the obligation was caused by its deliberate act or inaction; or
 - (c) such Party failed to comply with <u>Section 7.5.2</u> in respect of the Event of Force Majeure.

In no event shall the Customer be excused from any of its financial responsibilities or obligations under this Agreement, including in respect of any Banked Gas Account, or the settlement thereof.

7.6 <u>Payments by the Company</u>

If any payment is required to be made by the Company to the Customer pursuant to the terms of this Agreement, then such payment shall be processed by the Company and remitted to the Customer, as applicable, in accordance with the Company's normal monthly billing practise.

7.7 <u>Company's Set-Off Rights</u>

The Company is hereby authorized by the Customer, without demand for payment, and without any other formality, all of which are hereby waived, at any time and from time to time to set off, appropriate and apply any and all deposits (general or special, time or demand, provisional or final, in whatever currency) or security, including any cash or other amounts at any time held by the Company, and any and all amounts to be remitted by the Company to the Customer, together with any

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other obligations (in whatever currency) at any time owing by the Company to or for the credit or the account of the Customer now or hereafter existing under this Agreement or any Enbridge Agreement against any and all of the obligations of the Customer to the Company now or hereafter existing under this Agreement or any Enbridge Agreement, irrespective of whether or not the Company has made any demand under this Agreement or any Enbridge Agreement and although such obligations of the Customer may be contingent or unmatured (and for purposes of this provision, "contingent or unmatured" obligations refers only to the Customer's deficiency or surplus gas delivery obligation, if any, pursuant to any Enbridge Agreement, and the crystallization thereof as provided therein). Each of the Parties hereto hereby waives, to the extent lawful, any "reasonable period" which may be imposed by a court prior to the exercise of such set-off, appropriation and application. The rights of the Company under this Section 7.7 are in addition to other rights and remedies (including other rights of setoff, consolidation of accounts and liens) that the Company may have. The Company agrees to promptly notify the Customer at the time of or forthwith following any such setoff and application, but the failure to give such notice shall not affect the validity of such setoff and application.

Further, the Customer is hereby afforded a corresponding right to set off, appropriate and apply, as that provided to the Company above, *mutatis mutandis*.

ARTICLE 8 RECORD KEEPING

8.1 <u>Co-Operation</u>

The Customer acknowledges and agrees that (A) as the 'shipper' for purposes of the relevant Gas Transporter(s), the Customer may be in possession of information with respect to volumes of Gas delivered to the Company hereunder which may be required by the Company in the preparation of any statement or other document hereunder, and (B) they shall each co-operate with the Company to the extent necessary for the Company to obtain any information not in its possession.

8.2 <u>Errors</u>

If an error in a statement or other document is discovered, a correcting adjustment shall be made promptly in a subsequent statement in accordance with the *Transaction Rules*. Claims for errors shall be made promptly upon discovery.

8.3 Retention of Records

All charts and calculations upon which a statement or other document issued to the Customer is based, and the Company's books and records which relate solely to measurement and settlement for accounts hereunder, shall be retained by the Company for the longer of (A) three (3) years from the date of the relevant statement or such longer period as the Company determines to retain such records for its own purposes, and (B) the period while any claim which relates to such statement, and of which the Company receives written notice from the Customer within such one-year period, is outstanding; and shall be available for inspection by the Customer on reasonable prior notice during normal office hours of the Company.

8.4 Withholding

Notwithstanding anything in this Agreement to the contrary, the Company shall have the right to withhold (either by withholding payment or by withholding a credit to which the Customer might otherwise be entitled) an amount owing to the Customer by the Company equal to the amount of money then due, owing and unpaid by the Customer to the Company under this Agreement or, if applicable, under any Large Volume Distribution Contract entered into between the Company and the Customer (the "Withheld Amount"). Upon the Company ceasing to be entitled to hold any particular portion of a Withheld Amount the Company shall forthwith pay to the Customer an amount equal to such portion of the Withheld Amount.

ARTICLE 9 TERM AND TERMINATION

9.1 <u>Term</u>

Subject to the other terms and conditions of this Agreement, the term of this Agreement (the "**Term**") shall commence on the date first above written and shall continue until terminated in accordance with the provisions of this Agreement.

9.2 Rights of Termination

- 9.2.1 <u>Mutual Right to Terminate</u> Subject to the other provisions of this <u>Article 9</u>, either Party shall have the right to terminate this Agreement at any time, without cause, upon the earliest date to occur which is both:
 - (a) immediately following the expiry or termination of the last of the Pools established by the Customer pursuant to this Agreement; and
 - (b) not less than sixty (60) days and not more than one hundred twenty (120) days prior written notice to the other Party.
- 9.2.2 <u>The Company's Right to Terminate</u> Subject to the other provisions of this <u>Article 9</u> and in addition to the Company's rights of termination set out elsewhere in this Agreement, the Company shall have the right to terminate this Agreement:
 - (a) at any time upon the occurrence of an Event of Default; or
 - (b) at any time, without notice, upon the occurrence of a regulatory change established by a Governmental Authority, which causes, results in or requires such termination.
- 9.2.3 <u>Customer's Right to Terminate</u> Subject to the other provisions of this <u>Article 9</u>, the Customer shall have the right to terminate this Agreement if the Company fails to perform or observe any of its obligations under this Agreement on its part to be observed or performed and such failure shall continue unremedied for a period of thirty (30) days following notice thereof (giving particulars of the failure in reasonable detail) from the Customer to the Company. For certainty, termination of this

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Agreement under this Section shall not relieve any Party from any payment obligation to any other Party under this Agreement.

9.3 <u>Effects of Termination</u>

- 9.3.1 <u>Obligations of the Parties</u> Upon the termination of this Agreement, whether at the expiry of the Term or for any reason prior thereto:
 - (a) every Pool established hereunder shall forthwith be terminated and the Customer shall: (A) revert to System Gas; or (B) if the Company has received an appropriate Transaction Request, be transferred to another Pool; and
 - (b) the Company shall, as soon as reasonably practicable and in any event not later than ninety (90) days following termination, prepare and forward to the Customer, a statement setting out the status of the Banked Gas Account for the Customer and each such Pool; and forthwith following receipt of such statement, the Customer shall settle such obligations in a manner permitted by the Company and as set out in the Rate Handbook or the *Transaction Rules*; and for certainty, the Company shall have the right to deal with any such obligation in any manner set out or referred to in this Agreement;

provided that, notwithstanding any provision of the Rate Handbook or the *Transaction Rules* to the contrary, if this Agreement is terminated as a result of an Event of Default set out in <u>Section 9.4(c), (e) or (f)</u>, then settlement of such obligation shall be effected by payment made by the Customer immediately following delivery of such statement.

9.3.2 <u>Survival on Termination</u> - All provisions of this Agreement which by their terms are required to survive in order to permit the settlement in full of the obligations referred to in <u>Section 9.3.1(b)</u> as contemplated therein, shall survive the termination of this Agreement and continue in full force and effect in accordance with the terms of this Agreement for such period. Without limiting the foregoing, the following provisions shall so survive: <u>Article 8</u> - Record Keeping; <u>Section 9.3.1</u> - Obligations on Termination; <u>Article 10</u> - Indemnity, Disclaimers and Limitations; and <u>Section 12.8</u> - <u>Confidentiality</u>.

9.4 Events of Default

In addition to any other events set out in this Agreement, the occurrence of any one or more of the following events shall constitute a Default by a Customer under this Agreement and shall be considered an event of default (an "Event of Default") if such Default is not remedied prior to the expiry of the relevant notice period (if any) or the relevant cure period (if any) applicable to such Default as hereinafter set out:

(a) if the Customer fails to perform or observe any of its obligations under this Agreement (except as specifically provided in Section 9.4(b)) on its part to be observed and performed and such failure shall continue unremedied for a period of thirty (30) days following the earlier to occur of: (a) notice thereof (giving particulars of the failure in reasonable detail) from the Company to the Customer; or (b) knowledge by the Customer of the occurrence of such failure to perform or observe such obligation, provided that the Company has notified

- the Customer forthwith after the Company becomes aware of such failure to perform or observe such obligation; or
- (b) if the Customer fails to deliver the contracted MDV on any day of the term of the relevant Pool (as required pursuant to Section 2.2.1), and such failure shall continue unremedied (and for certainty, a failure can only be remedied before the end of the relevant day) following: (i) the sending by the Company to the Customer of notice of the failure, provided that such notice is sent not less than two (2) hours prior to the close of the second (2nd) NAESB nomination window for such day; or (ii) knowledge by the Customer of the occurrence of such failure; and provided that if the Customer nominates to deliver the contracted MDV on any day and then changes or otherwise amends any of its nominations for such day and as a result fails to deliver the contracted MDV for the relevant day, then such failure shall be deemed to be a failure for purposes of Section 9.4(c) regardless of whether the Company sends a notice as contemplated in (b)(i) above; or
- (c) if the Customer fails to deliver the contracted MDV on any day of the term of the relevant Pool (as required pursuant to <u>Section 2.2.1</u>) on three (3) separate occasions in any consecutive twelve (12) month period in respect of each of which failure the Company has provided a notice to the Customer pursuant to <u>Section 9.4(b)</u>, regardless of whether any of such failures have been remedied as provided in <u>Section 9.4(b)</u>; or
- (d) if the Customer files a petition in bankruptcy, makes application or files a petition seeking any re-organization, arrangement, composition or similar relief under any law regarding insolvency or relief for debtors or makes an assignment for the benefit of creditors, or if a receiver or receiver and manager, trustee or similar officer is appointed for the business or property of the Customer, or any part thereof, or if any involuntary petition, application or other proceeding under any bankruptcy or insolvency laws is instituted against the Customer and is not stayed, otherwise enjoined or discharged within fifteen (15) Business Days; or
- (e) if any execution, distress or other enforcement process, whether by court order or otherwise, which would have a material adverse effect on the financial viability of the Customer becomes enforceable against any property of the Customer; or
- (f) if the Customer ceases carrying on business in the ordinary course, commits any act of bankruptcy under *The Bankruptcy and Insolvency Act* or is wound up; or
- (g) if there occurs an 'Event of Default' of the Customer under any other Enbridge Agreement (as defined in the relevant Enbridge Agreement);

provided that each of the above-noted Events of Default has been inserted for the benefit of the Company and may be waived by the Company in whole or in part at any time by notice to the Customer, the Company may extend the period for the remediation of any such Event of Default (if any), provided

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that the Customer is then diligently pursuing the satisfaction thereof and demonstrates to the reasonable satisfaction of the Company that the steps being taken by the Customer are likely to satisfy the Event of Default within a reasonable period of time.

9.5 Rights and Remedies on an Event of Default

- 9.5.1 <u>Rights and Remedies of the Company</u> Upon the occurrence of an Event of Default, the Company may do any one or more of the following as the Company, in its sole and absolute discretion, may determine:
 - (a) the Company may terminate this Agreement in accordance with the provisions of this Article 9;
 - (b) the Company may suspend any one or more of its obligations under this Agreement;
 - (c) the Company may bring any action at law as may be necessary or advisable in order to recover damages and costs; and/or
 - (d) the Company may exercise any of its other rights and remedies provided for hereunder or which are otherwise available to it, including pursuant to <u>Sections 3.3, 3.4</u> and 7.7.
- 9.5.2 <u>Rights and Remedies of the Customer</u> Upon the occurrence of the event contemplated in <u>Section 9.2.3</u>, the Customer may do any one or more of the following as the Customer, in its sole and absolute discretion, may determine:
 - (a) the Customer may bring any action at law as may be necessary or advisable in order to recover damages and costs; and/or
 - (b) the Customer may exercise any of its other rights and remedies provided for hereunder or which are otherwise available to it.

ARTICLE 10 INDEMNITY, DISCLAIMERS AND LIMITATIONS

10.1 <u>Indemnity by Customer</u>

Subject to any limitations specifically set out in this Agreement, the Customer shall save harmless and indemnify the Company, its directors, officers, employees and agents from and against any and all liability (including injury, loss, damage, expense or other cost) to the Company, howsoever caused, resulting from, arising out of or relating to the negligence or wilful misconduct of the Customer or any of such Customer's employees or agents or any Person acting under the authority of or with the permission of such Customer. The Customer further agrees to indemnify and hold the Company, its directors, officers, employees and agents harmless from and against any Canadian federal or provincial income taxes resulting from any payment made under this <u>Section 10.1</u>.

10.2 <u>Indemnity by Company</u>

Subject to any limitations specifically set out in this Agreement, the Company shall save harmless and indemnify the Customer, its directors, officers, employees and agents from and against any and all liability (including injury, loss, damage, expense or other cost) to the Customer, howsoever caused, resulting from, arising out of or relating to the negligence or wilful misconduct of the Company or any of the Company's employees or agents or any Person acting under the authority of the Company. The Company further agrees to indemnify and hold the Customer, its directors, officers, employees and agents harmless from and against any Canadian federal or provincial income taxes resulting from any payment made under this Section 10.2.

10.3 <u>Limitations</u>

Notwithstanding any other provision of this Agreement, the liability of each Party, and their respective shareholders, directors, officers, employees and agents, to another Party, whether founded in tort or breach of contract or otherwise, shall be limited to the loss sustained by such other Party as a result of direct physical damage sustained by such other Party, including reasonable costs of repair or replacement. Without limitation, a Party shall not be liable for any indirect or consequential losses, including loss of profits, business interruption losses, or any losses as a result of claims by third parties. In no event shall a Party be liable for any aggravated or non-compensatory damages, including punitive or exemplary damages, whether by statute, in tort or contract.

ARTICLE 11 DISPUTE RESOLUTION

11.1 <u>Dispute Resolution Principle</u>

This <u>Article 11</u> establishes a framework and procedure under which the Parties shall, in good faith, use their reasonable efforts to resolve most disputes that arise under this Agreement (in each case, a "**Dispute**") without resort to litigation. In the event of any Dispute arising between the Parties, unless otherwise provided herein, the Parties shall use reasonable commercial efforts to settle such Dispute in the manner set out in <u>Section 11.2</u>. For certainty, such Disputes shall not include the ability of either Party to terminate this Agreement in accordance with the provisions hereof.

11.2 <u>Dispute Resolution Mechanism</u>

- 11.2.1 <u>Notice of Dispute</u> A Party claiming that a Dispute has arisen must give written notice (a "**Dispute Notice**") to the other Party specifying the nature of the dispute, the relief sought and the basis for the relief sought.
- 11.2.2 <u>Meeting between Operations Personnel</u> Within seven (7) Business Days of receipt of a Dispute Notice, the Parties must commence the process of attempting to resolve the Dispute by referring such Dispute to a meeting between the <u>Manager, Strategic and Key Accounts</u> (or the successor position thereof), on behalf of the Company, and an equivalent or similar manager on behalf of the Customer, (the "**Operations Personnel**") for discussion and resolution. The Operations Personnel shall consult, discuss and negotiate in good faith with the intention of reaching a just and equitable solution satisfactory to both Parties.

- 11.2.3 <u>Meeting between Senior Representatives</u> If a Dispute is not resolved to the mutual satisfaction of the Parties by the Operations Personnel within twelve (12) Business Days after the Dispute Notice has been delivered the Dispute shall be referred to the Parties' respective senior representatives (in the case of the Company, the <u>Vice-President, Operations</u> (or the successor position thereof); and in the case of the Customer, an equivalent or similar senior manager of the Customer) (the "Senior Representatives") for resolution. The Parties shall cause their respective Senior Representatives to meet as soon as possible in an effort to resolve the dispute.
- 11.2.4 <u>Non-Binding Mediation</u> If the Dispute is not resolved by the Senior Representatives to the mutual satisfaction of the Parties within twenty (20) Business Days after delivery of the Dispute Notice, then the Parties may agree to refer the Dispute to a private mediator agreed to between them. The Parties and the mediator shall conduct the mediation in accordance with procedures agreed to between them and all third-party costs (including those of the mediator) shall be shared equally by the Parties. There shall be no obligation of a Party to agree on a mediator or any procedures therefore, other than to act in good faith.

11.3 Alternative Resolution

If the Dispute is still not resolved to the mutual satisfaction of the Parties within sixty (60) days after delivery of the Dispute Notice, then either Party may require the Dispute to be resolved by litigation or such other legal means as are available to such Party, provided the Party seeking legal remedy has pursued resolution of the Dispute as contemplated in <u>Section 11.2</u>.

ARTICLE 12 GENERAL

12.1 Notice

All notices, directions, documents of any nature required or permitted to be given by one Party to the other pursuant to this Agreement (in each case, a "**Notice**") shall be in writing and shall be delivered personally or by courier or sent by facsimile as follows:

(a) in the case of the Company, to it at:

Enbridge Gas Distribution Inc. 500 Consumers Road North York ON M2J 1P8 Fax Number: (416) 495-5657

Attention: Manager, Contract Support and Compliance

(b) in the case of the Customer, to it's legal contact at the address set out below following the signature of the representatives of the Customer,

or at such other address of which the addressee may from time to time have notified the addressor pursuant to this <u>Section 12.1</u>. A Notice may be delivered by electronic internet communication provided the Parties have agreed in writing in advance to do so and have established in writing their respective addresses for such communication. A Notice shall be deemed to have been sent and received on the day it is delivered personally or by courier or by facsimile or by electronic internet communication. If such day is not a Business Day or if the Notice is received after ordinary office hours (at the time of place of receipt), the Notice shall be deemed to have been sent and received on the next Business Day.

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Notwithstanding the foregoing, any Notice given by the Company pursuant to <u>Section 9.4(b)</u>shall be deemed to have been sent and received on the date and at the time of transmission if sent by facsimile or e-mail to the Customer's legal contact at the fax number or e-mail address, as applicable, set out below following the signature of the representatives of the Customer.

12.2 <u>Time of the Essence</u>

Time is of the essence of this Agreement and of every provision of this Agreement. Extension, waiver or variation of any provision of this Agreement shall not be deemed to affect this provision and there shall be no implied waiver of this provision.

12.3 <u>Further Acts</u>

The Parties shall do or cause to be done all such further acts and things as may be reasonably necessary or desirable to give full effect to this Agreement. Without limiting the foregoing, each Party will at any time and from time to time execute and deliver or cause to be executed and delivered such further instruments and take such further actions as may be reasonably requested by the other Party in order to cure any defect in the execution and/or delivery of this Agreement.

12.4 <u>Amendment</u>

This Agreement may be amended only by written agreement of the Parties.

12.5 <u>Waiver</u>

Except as otherwise expressly set out herein, no waiver of any provision of this Agreement shall be binding unless it is in writing. No indulgence or forbearance by a party shall constitute a waiver of such party's right to insist on performance in full and in a timely manner of all covenants in this Agreement. Waiver of any provision shall not be deemed to waive the same provision thereafter, or any other provision of this Agreement at any time.

12.6 Assignment

The Customer may not sell, assign or transfer any of its interest in or rights or obligations under this Agreement, in whole or in part without the prior written approval of the Company, which approval will not be unreasonably withheld or delayed.

12.7 <u>Enurement and Binding Effect</u>

This Agreement shall enure to the benefit of the parties hereto and their respective permitted successors and permitted assigns and be binding upon the parties hereto and their respective successors and permitted assigns.

12.8 <u>Confidentiality</u>

As a result of the business relations between the Parties pursuant to this Agreement, a Party (the "Receiving Party") may acquire confidential information regarding the business and affairs of another Party (the "Disclosing Party"). The disclosure of any of such confidential information to competitors of the Disclosing Party or to the general public could be detrimental to the interests of the

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Disclosing Party. All such confidential information acquired or obtained by the Receiving Party will not be used by the Receiving Party, or disclosed to others (other than directors, officers, employees, representatives and agents of the Receiving Party who require same with respect to the fulfillment of such Party's obligations under this Agreement), either directly or indirectly, unless the Disclosing Party provides its prior written consent. The foregoing obligations shall remain until such time as the confidential information (i) becomes public through no fault or act of the Receiving Party, or (ii) is furnished to the Receiving Party without restriction on disclosure, or (iii) is required to be disclosed by the Receiving Party pursuant to a Required Order.

12.9 Counterparts

This Agreement may be executed in several counterparts, each of which shall be deemed to be an original, and all such counterparts together shall constitute one and the same instrument and notwithstanding their date of execution shall be deemed to be made and dated as of the date hereof.

IN WITNESS WHEREOF the Parties have executed this Agreement as of the year and date first above written.

ENBRIDGE GAS DISTRIBUTION INC.

By:			
	Name:		
	Title:		
By:			
	Name:		
	Title:		

[end of page – Customer signature on next page]

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CUSTOMER:

name:_

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	Name: Title: Name: Title:
Legal Contact Information and Address for Service of Customer:	Address for Service of Customer for purposes only of a Notice given under Section 9.4(b):
Legal Contact:	Legal Contact:
Name:	Name:
Position/Title:	Position/Title:
Department:	Department:
Business Phone No.:	Business Phone No.:
Fax No:	Fax No:
E-Mail Address:	E-Mail Address:
Mailing Address:	Note: this is the 'legal contact' for purposes of Section 9.4(b)

Note: this is the 'legal contact' for purposes of Section 12.1, except with respect to Notice given under Section 9.4(b)

Courier Address:

Schedule "A"

TERMS AND CONDITIONS OF ASSIGNMENT OF COMPANY CAPACITY

The Company is a party to a contract with TransCanada PipeLines Limited ("TCPL") in respect of the firm transportation service to the Company's delivery area (the "FT-Contract").

The Company has agreed to assign part of the Company's service entitlement as shipper under the FT-Contract (an "Assignment") pursuant to <u>Section 2.5</u>, and subject to the terms and conditions of this *Schedule "A"*.

- 1. Each Assignment shall commence and terminate in accordance with the *Transaction Rules*. During the operative term of each Assignment, the Company assigns to the Customer, and the Customer accepts from the Company, a part of the Company's service entitlement as shipper under the FT-Contract equal to that number of gigajoules per day (the "Assigned Volume") as arises pursuant to the relevant Transaction Request from the Customer, together with the corresponding rights and obligations of the Company as shipper under the FT-Contract and under the Firm Service (FT) Toll Schedule and the General Terms and Conditions contained in the relevant Gas Transporter's Transportation Tariff, filed with the National Energy Board, as same may be hereafter revised or superseded (collectively, the "FT Tariff").
- 2. During the operative term of each Assignment, the Customer shall perform and observe the covenants and obligations of the Company as shipper contained in the FT-Contract and the FT Tariff insofar as they pertain to the Assigned Volume, to the same extent as the Customer would be obligated so to do were the Customer a party to the FT-Contract, as shipper, with a service entitlement thereunder equal to the Assigned Volume.
- 3. Each Assignment shall be in full force and effect in accordance with the *Transaction Rules*, and subject to paragraph 4 hereof, shall be operative for a term equal to: (A) in the case of an Assignment made pursuant to <u>Section 2.5.1</u>, the period during which the relevant Pool is and remains in full force and effect; or (B) in the case of an Assignment made pursuant to <u>Section 2.5.2</u>, the duration of such Pool suspension request; provided that the operative term of each Assignment shall not extend beyond the operative term of the relevant FT-Contract, as same may be renewed or otherwise extended by the Company in accordance with the FT Tariff and TCPL's contractual practice and procedure in that regard.
- 4. In the event that the Customer does not comply with paragraph 2 hereof, the Company shall have the right to terminate the relevant Assignment by following the termination procedure set forth in the FT Tariff as if the Company were TCPL, the Customer were the Shipper and the relevant Assignment were the FT-Contract for this purpose.
- 5. The Company will request TCPL to acknowledge each Assignment and to treat the Customer as shipper with a service entitlement under the FT-Contract equal to the Assigned Volume during the operative term of the relevant Assignment. The Customer hereby consents to such request and to such treatment, and for this purpose the Customer declares that all notices, nominations, requests, invoices, and other written communications may be given by TCPL to the Customer in accordance with Section 12.1(b) of the Gas Delivery Agreement.

- 6. The Customer acknowledges that the Company will not seek TCPL's consent to an Assignment and that the Company accordingly is and will remain obligated to TCPL to perform and observe the covenants and obligations of shipper that are contained in the FT-Contract and the FT Tariff in regard to the Assigned Volume insofar as TCPL is concerned. Consequently, the Customer shall indemnify the Company for and hold the Company harmless from all charges that TCPL may be entitled to collect from the Company under the assigned portion of the FT-Contract and the FT Tariff in regard to the Assigned Volume in the event that the Customer fails to pay TCPL.
- 7. The Customer shall be entitled to sub-assign all or part of the service entitlement applicable to the Assigned Volume, together with the corresponding rights and obligations under the FT-Contract and the FT Tariff, to a third party by assigning all or part of its rights and obligations under this Assignment; provided that, in the light of the Company's continuing obligation to TCPL and the Customer's indemnity to the Company in that regard pursuant to paragraph 6, no such assignment shall be made, or relieve the Customer of its obligations to the Company hereunder, without the Company's prior written consent, which shall not be unreasonably withheld.
- 8. Notwithstanding anything to the contrary herein set forth or implied, the Company reserves and retains for itself exclusively the option or right to renew or otherwise extend the operative term of the FT-Contract in accordance with the FT Tariff and TCPL's contractual practice and procedure in that regard.
- 9. This Assignment and the rights and obligations of the parties hereunder are subject to all valid and applicable present and future laws, rules, regulations, and orders of any governmental or regulatory authority having jurisdiction or control over the parties hereto or either of them, or over the FT-Contract, the FT Tariff, and the assignment or sub-assignment of the service entitlement thereunder.
- 10. The Customer acknowledges that the Company has made available to it a true copy of the FT-Contract and declares that it has (or will obtain directly from TCPL) a copy of the FT Tariff.

Exhibit I.D1.EGDI.BOMA.23

Page 1 of 2

BOMA INTERROGATORY #23

INTERROGATORY

Ref: Ibid, p21

For what period does a "medium term weather forecast" make predictions? How accurate has it been since EGD began using it?

RESPONSE

As a part of the development of its Gas Supply Plan the Company will identify a Dawn purchase requirement for the winter period i.e. November to March. The Company has stated that it will manage that supply requirement through a series of seasonal, term and monthly RFPs as well as daily purchases. Once the seasonal and term RFPs have been completed there will be a remaining level of Dawn requirement to be acquired to meet budget demand. This remaining requirement would be acquired either through a monthly RFP or daily purchase.

As discussed on page 21 of 27 of Exhibit D1, Tab 2, Schedule 2 the use of a medium term forecast is intended to provide Enbridge with the ability to adjust planned month-ahead supplies sooner. Below is an example of how a medium term forecast would assist in the planning process.

In mid- December the Company will issue RFPs for various supplies for the month of January to fill various pipeline contracts (i.e., TCPL and Vector) as well as for Dawn purchases. Assume for illustrative purposes that after making seasonal and term arrangements, EGD is left with a remaining daily requirement of 400 mmcf / day at Dawn based upon budget demand. If the medium term forecast was to indicate that the expected degree days in January are in line with budgeted degree days then the Company could proceed with an RFP with the intent to acquire or lock up some amount of that remaining Dawn requirement, for example, 200 mmcf / day leaving 200 mmcf / day to be purchased on the day. However, if the medium term forecast suggested that January was to be colder and the daily requirement rose to 600 mmcf / day and then buy the remaining 200 mmcf on the day. Conversely, if the medium term forecast indicated that January was to be warmer and the daily requirement was to decrease to 200 mmcf / day, the Company could then elect not to issue an RFP.

EGD began using a medium term forecast as part of its gas supply planning criteria in 2015 as a result of the extreme weather experienced in the winter of 2013 / 14. The

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Company provided a response to a Board Staff interrogatory (EB-2014-0276 Exhibit I.D1.EGDI.STAFF.11) which explained what would trigger Enbridge to include in its demand assessment the medium term weather forecast. While the forecasts themselves were never intended to be judged by how accurate they were, this has been a useful tool. In 2015, when demand was colder than budget, EGD avoiding buying a sizeable amount of gas in the day market and in 2016 and 2017, when demand was lower than budget, the Company avoided acquiring unnecessary monthly supplies.

Exhibit I.D1.EGDI.BOMA.24

Page 1 of 1

BOMA INTERROGATORY #24

INTERROGATORY

Ref: Exhibit D1, Tab 2, Schedule 3, p4, Nexus Delivery

- (a) Will the landed price of the gas purchased in Chicago to backfill the delayed Nexus supply to Vector cost more or less than gas purchased pursuant to the Nexus contract? Has EGD already purchased gas for delivery via Nexus? Does EGD have FM or other contracted protection on gas it has already purchased at Dominion North or other Marcellus/Utica purchase points?
- (b) What is the contingency plan?
- (c) Has FERC now approved the Nexus pipeline for 2018? If not, when is FERC approval likely to occur? Is there material risk that Nexus will not be approved?

RESPONSE

- a) EGD has yet to make any supply arrangements for gas to be purchased at Dominion South and therefore is unable to do a price comparison.
- b) & c)

Please see response to Board Staff Interrogatory # 7 at Exhibit I.D1.EGDI.STAFF.7.

Exhibit I.D1.EGDI.BOMA.25

Page 1 of 1

BOMA INTERROGATORY #25

INTERROGATORY

Ref: Ibid, p7, paragraph 6

Why is it necessary for EGD to receive its delivery volume to the service area through additional peaking service, to replace deliveries to the franchise area by Ontario T-Service customers opting to move to Dawn delivery service? Please explain fully. What notice does EGD require from migrant customers prior to their switching to Dawn delivery service? What has been the incremental cost to ratepayers (in 2017) and forecast in 2018 to backfill the missing supply with peaking service?

RESPONSE

Volumes received under the Dawn T-Service option will require transportation to get the gas from Dawn to the franchise area. Using existing contracted capacity from Dawn to Parkway on the Union system and from Parkway to CDA on the TCPL system will leave a supply deficiency in the CDA on Peak Day in the future.

As part of the Dawn Access Consultative, EGD asked Direct Purchase customers to express their interest in converting their pools from OTS/WTS to DTS with the proviso that conversions would only take place after necessary changes were made to Entrac and that enhancements were made to the TCPL system. Assuming these upgrades were complete, the conversion would take place upon the individual customers' renewal date on or after November 1, 2017.

Because DTS is not becoming effective until November 1, 2017 there was no impact on the forecasted peaking service requirement in 2017 and as described in response to Board Staff Interrogatory # 8 (Exhibit I.D1.EGDI.STAFF.8) there was a slight reduction in the forecasted peaking requirement in 2018 versus 2017.

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BOMA INTERROGATORY #26

INTERROGATORY

Ref: Ibid, p8

Please provide illustration of potential high deliverability seasonal exchange to meet a winter Dawn requirement.

RESPONSE

Please see response to FRPO Interrogatory #10, at Exhibit I.D1.EGDI.10.

Exhibit I.D1.EGDI.BOMA.27

Page 1 of 1

BOMA INTERROGATORY #27

INTERROGATORY

Ref: General

Please provide a description of the proposed changes in the new EGD pension plan from the current plan. Please describe in sufficient detail to allow parties to understand clearly what the changes were, and why they were made.

RESPONSE

Please refer to Tables 1, 2 and 3 in Appendix B (page 11) of the Mercer report (found at Exhibit D1, Tab 5, Schedule 1, Appendix 1) for a description of the changes to the pension plan.

The main reasons for these changes are to:

- 1) Harmonize the pension programs of Enbridge and Spectra Energy;
- Provide consistent pension benefits (i.e., same DB formula and same required contributions for Canadian employees) while ensuring that the program is competitive in each employee location by adjusting the level of pension credits; and
- 3) Improve the long-term financial sustainability of the pension plan by introducing a 5 year DC participation period for new hires and by eliminating cost of living adjustments ("COLA") for future service.

Witness: R. Stelmaschuk

Exhibit I.D1.EGDI.BOMA.28

Page 1 of 5
Plus Attachments

BOMA INTERROGATORY #28

INTERROGATORY

Ref: Exhibit D1, Tab 5, Schedule 1, p2

- (a) Please provide the 2016 and 2017 actual and forecast/actual to date in the Table at p2 of 4.
- (b) Please provide any internal study or report conducted on the harmonization of the pension plans for employees of Enbridge Inc. and Spectra Inc.
- (c) Please provide an explanation as to why the forecast 2018 cash requirement is approximately \$6 million higher than the 2018 accrual expense in the 2018 utility placeholder in the Table on p2.
- (d) Please provide an explanation in text of each of the entries (columns) on the two tables in Appendix C to the Mercer Report (pp14 and 15). Please explain the changes shown in each of lines 1 through 9 for the 2018 Pension Plan accounting expenses, and cash requirements determinants, which, when aggregated, produce the numbers shown on p2 of 4, for each of listed plans.
- (e) Please provide copies of the "Report" and the two "Presentations" referred to at p7 of the Mercer Report.

RESPONSE

- a) In Attachment #1 to this response, the table provided at page 2 of Exhibit D1, Tab 5, Schedule 1, has been expanded to include 2016 actual pension and OPEB amounts, and the current forecast of 2017 amounts.
- b) Please refer to the Mercer Report (Exhibit D1, Tab 5, Schedule 1, Appendix 1) and responses to Interrogatories for information on the new harmonized pension plan.
- c) The cash requirements are determined in accordance with applicable pension legislation and Enbridge's funding policy, whereas accrual expense is determined in accordance with US accounting standards. For defined benefit pension plans and nonpension post-retirement plans, funding/cash and accounting approaches differ in both assumptions and methodology so it is not expected that the two should be equal.

Witnesses: Mercer

R. Stelmaschuk

Exhibit I.D1.EGDI.BOMA.28

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Plus Attachments

Typically for a defined benefit pension plan, cash requirements are comprised of current service cost and special payments. Explanations of these components are described in response to part (d) of this Interrogatory. Assumptions are determined in accordance with accepted actuarial standards for the purposes of the funding valuations, subject to Enbridge's funding policy. The non-pension post retirement plan ("OPEB Plan") is unfunded and EGDI contributes on a cash basis as benefits are paid.

The accrual expense is comprised of current service cost, interest cost, expected return on assets, amortization of net actuarial loss or gain, and amortization of prior service cost or credit. Explanations of these components are described in response to part (d) of this Interrogatory. Assumptions are management's best estimate, with the exception of the discount rate, which is determined by reference to market yields on high-quality corporate bonds.

d) Exhibit D1, Tab 5, Schedule 1, Appendix 1, Page 14 of the Mercer Report summarizes the projected 2018 net periodic benefit cost (i.e., accrual expense) for each of the pension and non-pension post-retirement benefit plans for which EGDI has some share. Under US accounting standards, the net periodic benefit cost is the amount recognized in an employer's financial statements as the cost of a pension or non-pension post-retirement benefit plan for a given period. Components of net periodic benefit cost are service cost, interest cost, expected return on assets, amortization of net actuarial gain or loss, and amortization of prior service cost or credit. The components in each row sum to the accrual expense amount of \$20.8M in the final column titled "P&L Charge (Credit)".

In Exhibit D1, Tab 5, Schedule 1, Page 2, the **2018 Forecasted Accrual Expense** in lines 2 through 5 and 7 corresponds, for each plan, with the P&L Charge (Credit) in Appendix 1 (page 14). The EGD RPP P&L Charge (Credit) from Appendix C is segregated between DC Current Service Cost (corresponding to line 6), Pension Credits (corresponding to line 8) and all other components which comprise the DB net periodic benefit cost (corresponding to line 1). Each of the components is explained further below.

DC Current Service Cost – The amount recognized in a period determined as the employer contribution attributed by the defined contribution formula to services rendered by employees during that period.

Witnesses: Mercer

R. Stelmaschuk

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DB Current Service Cost (pension plans) – The amount recognized in a period determined as the actuarial present value (using accounting assumptions) of benefits attributed by the defined benefit formula to services rendered by employees during that period less employee required contributions to the pension plan over that same period.

Current Service Cost (OPEB plan) – The amount recognized in a period determined as the actuarial present value of benefits attributable to service during the year.

Interest Cost – The amount recognized in a period determined as the increase in the projected benefit obligation due to the passage of time.

Expected Return on Assets – The amount recognized in a period determined as the expected increase in the plan assets due to the passage of time.

Amortization of Net Actuarial Loss (Gain) – The portion, if any, of the unrecognized accumulated net actuarial experience different than expected to be recognized in a period.

Amortization of Prior Service Cost – The amount recognized in a period, if any, due to the cost of retroactive benefits granted in a plan amendment. Retroactive benefits are granted in a plan amendment (or initiation) that are attributed to service rendered prior to the amendment.

Although it is not a component of the net periodic benefit cost, **Pension Credits** are the amount that will be provided to employees by Enbridge as a result of changes to the plan design. This amount is a compensatory cost that relates to the pension plan.

Exhibit D1, Tab 5, Schedule 1, Appendix 1, Page 15 of the Mercer Report summarizes the projected 2018 contribution amounts (i.e., cash requirement) for each of the pension and non-pension post-retirement benefit plans for which EGDI has some share. Pension plan contribution requirements are determined in accordance with applicable pension legislation and Enbridge's funding policy. The EGD RPP is an Ontario registered pension plan that must comply with the minimum standards of the *Pension Benefits Act* (the "PBA"). The EI RPP is a federally registered pension plan and must comply with the minimum standards of the *Pension Benefits Standards Act*

Witnesses: Mercer

R. Stelmaschuk

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(the "PBSA"). Both plans are also subject to requirements of the *Income Tax Act* of Canada. The EI SPP, SERP and SSERP are funded supplemental pension arrangements and are not subject to minimum pension standards. The OPEB Plan is unfunded which EGDI funds on a cash basis as benefits are paid. The components in each row sum to the amount of \$26.92M in the final column titled "Total Annual Employer Contributions".

In Exhibit D1, Tab 5, Schedule 1, Page 2, the "2018 Forecasted Cash Requirement" in lines 2 through 5 and 7 corresponds for each plan with the Total Annual Employer Contributions in Appendix 1 (page 15). The EGD RPP Total Annual Employer Contributions from Appendix 1 is segregated between DC Current Service Cost (corresponding to line 6), Pension Credits (corresponding to line 8) and all other components which comprise the DB contribution requirements (corresponding to line 1). Each of the components is explained further below.

DC Current Service Cost – The amount determined as the employer contribution in accordance with the plan contribution formula for services rendered by employees.

Pension Credits – The amount that will be paid to employees by Enbridge to partially offset the employee required contribution to the DB plan. This amount is a compensatory cost that relates to the pension plan.

Note that DC Current Service Cost and Pension Credits are equal between Appendix C and Appendix D.

DB Current Service Cost – The amount determined as the actuarial present value (using funding assumptions) of benefits attributed by the defined benefit formula to services rendered by employees during that period less employee required contributions to the pension plan over that same period.

Note that the DB Current Service Cost will not be the same as Appendix C due to differences in assumptions and methods.

Special Payments – The amount, if any, that is required to eliminate a funding deficit. Special payment funding requirements vary by jurisdiction. Generally speaking, the plan liabilities are measured on both a short-term (solvency) basis and a long-term

Witnesses: Mercer

R. Stelmaschuk

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(going concern) basis. If a deficit exists on either basis, the company may be required to eliminate that deficit over a prescribed period appropriate to the liability measure.

Benefits Paid Directly – The expected benefits that are to be paid directly by EGDI based on the provisions of the plan, accounting valuation economic/demographic assumptions and expected retiree claims experience.

e) Attached is the requested report (I.D1.EGDI.BOMA.28_Attachment 2.pdf), and presentations (I.D1.EGDI.BOMA.28_Attachment 3.pdf) and (I.D1.EGDI.BOMA.28_Attachment 4.pdf). Please note that we have only included sections relevant to the data, assumptions, methods, and provisions of these documents referenced in the Mercer Report.

Witnesses: Mercer

R. Stelmaschuk

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.BOMA.28 Attachment 1 Page 1 of 1

	Plan	2018 Forecasted	2018 Forecasted	2017 Forecasted	2017 Forecasted	2016 Actual	2016 Actual Cash
		Accrual Expense	Cash Requirement	Accrual Expense	Cash Requirement	Accrual Expense	Requirement
		(\$ Millions)	(\$ Millions)	(\$ Millions)	(\$ Millions)	(\$ Millions)	(\$ Millions)
-	Enbridge RPP Plan	\$12.72	\$20.55	\$18.14	\$43.09	\$17.88	ΞZ
2	Enbridge SERP Plan	\$0.08	ij	\$0.0\$	\$0.01	\$0.02	\$0.01
რ	Enbridge SSERP Plan	(\$0.15)	ij	(\$0.15)	Ξ̈̈́Z	(\$0.14)	ΞZ
4.	Enbridge portion of	(\$0.29)	\$0.07	(\$0.22)	\$0.06	(\$0.17)	\$0.0\$
	Enbridge Inc's RPP Plan						
5.	Enbridge's portion of	\$1.18	\$0.05	\$1.51	\$2.66	\$1.44	\$0.05
	Enbridge Inc's SPP Plan						
9	DC Plan	\$0.36	\$0.36	\$0.65	0.65	\$0.80	\$0.80
7.	OPEB Plan	\$5.59	\$4.58	\$5.08	\$3.85	\$5.07	\$3.76
œ	Other – Pension Credits	\$1.31	\$1.31	Ē	Ξ̈̈́Z	Ē	ΞZ
ი	Total Pension and OPEB	\$20.80	\$26.92	\$25.10	\$50.32	\$24.90	\$4.71
	expense						
10.	PTUVA Adjustment			(\$0.37)		\$9.6\$	
<u>+</u>	Amount included in Utility	\$20.80	\$26.92	\$24.73	\$50.32	\$34.56	\$4.71
	Results						

Witnesses: R. Small

R. Stelmaschuk



PENSION PLAN FOR EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2016

SEPTEMBER 2017

Financial Services Commission of Ontario Registration Number: 0242016 Canada Revenue Agency Registration Number: 0242016



PENSION PLAN FOR EMPLOYEES OF ENBRIDGE GAS
DISTRIBUTION INC. AND AFFILIATES

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound up in the future. In fact, even if the plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the *Pension Benefits Act* (Ontario), the Income Tax Act and related regulations that are effective as of the valuation date. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this report.

MERCER i

APPENDIX B

Plan Assets

The pension fund is held by CIBC Mellon. In preparing this report, we have relied upon the auditors' report signed by Price Waterhouse Coopers LLP. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets⁸

The pension fund transactions since the last valuation are summarized in the following table:

	2016	2015	2014
January 1	\$943,814,000	\$932,485,000	\$837,980,000
PLUS			
Members' contributions	\$0	\$0	\$0
Company's contributions	\$0	\$0	\$41,001,000
Investment Income	\$73,876,000	\$57,309,000	\$96,669,000
	\$73,876,000	\$57,309,000	\$137,670,000
LESS			
Pensions paid	\$41,096,000	\$38,342,000	\$36,288,000
Lump-sums paid	\$5,450,000	\$3,236,000	\$1,930,000
Administration and investment fees	\$5,635,000	\$4,402,000	\$4,947,000
	\$52,181,000	\$45,980,000	\$43,165,000
December 31	\$965,509,000	\$943,814,000	\$932,485,000
Gross rate of return ⁹	8.05%	6.29%	11.55%
Rate of return net of expenses ¹⁰	7.41%	5.81%	10.93%

We have tested the pensions paid, the lump-sums paid, and the contributions for consistency with the membership data for the Plan members who have received benefits. The results of these tests were satisfactory.

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⁸ In-transit amounts are included in the beginning and ending values in accordance with the audited statements. The DB component assets are included in this section and the DC component assets are included in Section 3.

⁹ Assuming mid-period cash flows.

¹⁰ Assuming mid-period cash flows.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Investment Policy

The plan administrator has adopted an amended statement of investment policy and procedures. The amended policy was approved in August 2017. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations and individual investments.

The constraints on the asset mix based on the amended statement of investment policy and procedures are provided for information purposes:

	Investment F	Policy – Amended	l as of August 2017
	Minimum	Target	Maximum
Canadian equities	7.0%	10.0%	13.0%
Foreign equities	21.0%	30.0%	39.0%
Fixed income – universe	14.0%	20.0%	26.0%
Fixed income – real return	7.0%	10.0%	13.0%
Infrastructure	4.0%	9.0%	14.0%
Real estate	4.0%	9.0%	14.0%
Private equity	0%	6.0%	9.0%
Private debt	0%	6.0%	9.0%
Cash and cash equivalents	0.0%	0.0%	3.0%
	-	100%	

It is our understanding that the plan assets are transitioning to the target asset mix as new strategies are implemented and new managers are selected.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

The constraints of the prior investment policy and the actual asset mix at the valuation date are provided below for informational purposes:

	In	vestment Polic	у	Actual Asset Mix as at
	Minimum	Target	Maximum	December 31, 2016
Canadian equities	18.0%	21.0%	24.0%	21.5%
Foreign equities	17.0%	23.5%	30.0%	25.9%
Fixed income – universe	24.0%	30.0%	36.0%	27.3%
Fixed income – real return	7.0%	10.0%	13.0%	7.8%
Infrastructure	5.0%	9.0%	13.0%	9.4%
Real estate	3.0%	6.5%	10.0%	7.2%
Cash and cash equivalents	0.0%	0.0%	3.0%	0.9%
	•	100%	_	100%

Because of the mismatch between the Plan's assets (which are invested in accordance with the above investment policy) and the Plan's liabilities (which tend to behave like long bonds) the Plan's financial position will fluctuate over time. These fluctuations could be significant and could cause the Plan to become underfunded, or overfunded even if the Company contributes to the Plan based on the funding requirements presented in this report.

APPENDIX C

Methods and Assumptions - Going Concern

Valuation of Assets

For this valuation, we have used the market value of assets adjusted for in-transit amounts.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits and absent additional contributions.

As required under the Act, a funding shortfall will be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age distribution of the group remains constant.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	5.75%	5.50%
Inflation:	2.00%	2.25%
ITA limit / YMPE increases:	2.50%	2.75%
Pensionable earnings increases:	2.50% plus age-based merit and promotion scale	3.50%
Post retirement pension increases (50%):	1.00%	1.125%
Post retirement pension increases (55%):	1.10%	1.2375%
Retirement rates:	Revised age-related table	Age-related table
Termination rates:	Revised age-related table	Age-related table
Mortality rates:	100% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	100% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using CPM Improvement Scale B (CPM-B)
Form of benefit elected upon termination:	One-third of members receive a pension from the plan and two-thirds elect a lump sum transfer	One-third of members receive a pension from the plan and two-thirds elect a lump sum transfer
Actuarial basis for benefits assumed to be settled through a lump sum:	Discount rate: 4.00% Mortality rates: CPM2014 with fully generational improvements using CPM-B	Consistent with 2011 CIA Standard
Disability rates:	None	None
Eligible spouse at retirement:	80%	80%
Spousal age difference:	Male 3 years older	Male 2 years older
DB/DC choice:	Continue in current Component	Continue in current Component

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Assumption		Current valuation	Previous valuation
Pensionable bonus rate	Union	5%	5%
for non SME ¹¹ :	Non-union	12%	12%
Bonus load:		135%	125%

The assumptions are best estimates with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Age-Related Tables

Sample rates from the age-related tables are summarized in the tables below.

Age Based Merit and Promotion Scale

	Merit and Promotion		
Age	Non-SME	SME	
<30	3.50%	3.75%	
30 - 39	2.50%	2.75%	
40 – 49	1.50%	1.75%	
50 – 54	0.50%	1.25%	
55+	0.50%	0.75%	

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¹¹ For SMEs, the actual target bonus is provided in the census data by member,

Termination and Retirement

_			Retirement – Not eligible for	Retirement – Eligible for
Age	Termination – Male	Termination – Female	unreduced retirement	unreduced retirement
20	5.0%	5.0%	0.0%	0.0%
25	5.0%	5.0%	0.0%	0.0%
30	5.0%	5.0%	0.0%	0.0%
35	4.6%	4.6%	0.0%	0.0%
40	3.0%	3.0%	0.0%	0.0%
45	2.5%	2.5%	0.0%	0.0%
50	1.5%	1.5%	0.0%	0.0%
55	0.0%	0.0%	5.0%	17.5%
56	0.0%	0.0%	5.0%	17.5%
57	0.0%	0.0%	5.0%	17.5%
58	0.0%	0.0%	5.0%	17.5%
59	0.0%	0.0%	5.0%	17.5%
60 – 64	0.0%	0.0%	17.5%	17.5%
65 – 69	0.0%	0.0%	50.0%	50.0%
70	0.0%	0.0%	100.0%	100.0%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken the rate of pay on December 31, 2016, and assumed that such pensionable earnings will increase at the assumed rate on April 1st each year.

Pensionable Bonuses

Since the benefits accrued by Senior Management Employees (the "SMEs") after December 31, 2007 and by non-SME members after June 30, 2001 are based on pensionable earnings plus 50% of actual bonuses received by the member, it is necessary to make an assumption about projected bonuses. For this valuation, actual bonuses for non-SME members have been estimated with an assumed target bonus rate of 12% for non-union members, and 5% for union members. For SME members, actual bonuses are assumed equal to that member's target bonus.

The projected actual bonuses described above were increased by 35% to reflect an expectation that an individual's target bonus at retirement may be higher than it is currently due to promotion, and that annual bonuses vary from year to year but only the best three out of the last five are included in the final average earnings calculation.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund net of fees and less a margin for adverse deviations. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels, the expected time horizon over which benefits are expected to be paid, and the target asset mix specified in the Plan's investment policy.
- Additional returns assumed to be achievable due to active equity management equal to the fees
 related to active equity management. Such fees were determined by the difference between the
 provision for total investment expenses and the hypothetical fees that would be incurred for passive
 management of all assets.
- Implicit provision for investment expenses determined as the expected rate of investment expenses to be paid from the fund in the future.
- Implicit provision for non-investment expenses determined as the expected rate of non-investment expenses to be paid from the fund in the future based on recent experience and an assessment of future expectations.
- A margin for adverse deviations of 0.51%

The discount rate was developed as follows:

Assumed investment return	6.59%
Additional returns for active management	0.31%
Active management expense provision	(0.31%)
Passive investment expense provision	(0.05%)
Implicit non-investment expense provision	(0.28%)
Margin for adverse deviation	(0.51%)
Net discount rate	5.75%

Inflation

The inflation assumption is based on the mid-point of the Bank of Canada's inflation target range of between 1% and 3%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on Company expectations and reflects inflation of 2% plus an allowance of 0.5% to reflect real economic growth and productivity gains in the economy and an age based allowance to reflect merit and promotion.

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PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Post-Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above.

Retirement Rates

Retirement rates are typically developed taking into account plan provisions and the past experience of the Plan. Accordingly, the rates of retirement have been developed as our expectation of the best-estimate rates given the Plan's provisions and Plan experience over the years 2009 to 2013. Future experience will be reviewed for consistency with these rates.

Termination Rates

Due to the size of the Plan, there is no meaningful termination experience. The assumption is based on an industry table that is consistent with our experience adjusted for plan experience over the years 2009-2013. Future experience will be reviewed for consistency with these rates.

Mortality Rates

The assumption for the mortality rates is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014.

Due to the size of the Plan, specific data on plan mortality experience is insufficient to determine the mortality rates. After considering plan-specific characteristics, such as the type of employment, the industry experience, pension and employment income for the plan members, and data in the CPM study, it was determined to use the CPM mortality rates from the private sector without adjustment.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. The Canadian Pensioners Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014 included CPM Improvement Scale B (CPM-B).

A draft report released by the Canadian Institute of Actuaries Task Force on Mortality Improvement (Task Force) in April 2017 provides an analysis of the rate of mortality improvement for the Canadian population and provides a proposed new mortality improvement scale (MI-2017) for the purpose of reflecting future mortality improvement in Canadian actuarial work. In particular, MI-2017 includes different historical improvement rates compared to CPM-B and reflects higher long-term mortality improvement rate assumptions than CPM-B. MI-2017 would generally result in higher life expectancies than CPM-B. We will review the mortality improvement scale in a future valuation, pending the release of the final Task Force report.

For the present valuation, we have continued to use the CPM-B scale without adjustment, which is a reasonable outlook for future mortality improvement.

Based on this assumption, the life expectancy of a member aged 65 at the valuation date is 21.6 years for males and 24.1 years for females.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

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PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Form of Benefit Elected and Cost of Future Lump Sums

Due to the size of the Plan, there is no meaningful experience for the percentage of eligible plan participants that will elect to receive their benefit as a lump sum transfer from the plan. The assumption is based on our experience with similar plans and employee groups.

The cost of future lump sums will depend on the level of market interest rates at the time the lump sum is paid and any changes in the applicable actuarial standards for the determination of pension plan commuted values. The assumed cost of future lump sums is based on the average expected level of market interest rates over the period during which lump sums are expected to be paid, taking into account market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels. We have also assumed that future lump sums elected by eligible plan participants will be calculated using the new mortality basis applicable under the actuarial standards since October 2015.

Eligible Spouse

The assumption is based on an experience study conducted in 2014 on the marital status of retirees in the 5 year period ending in 2013. The results of the study were also consistent with industry experience. Actual marital status used for retirees.

Spousal Age Difference

The assumption is based on recent Plan experience showing males are typically three years older than their spouse.

Defined Benefit / Defined Contribution Choice

The current service cost depends on the members' participation in the defined benefit or defined contribution component of the Plan. Since contributions are made as a percentage of pensionable earnings they automatically adjust when members change provisions.

APPENDIX D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

The Standards of Practice of the Canadian Institute of Actuaries require that the scenario upon which the hypothetical wind-up valuation is based be postulated. However, there are no benefits under the plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. No benefits payable on plan wind-up were excluded from our calculations. The plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the solvency liability, the cost of future indexing has been excluded from solvency liability as permitted under the *Ontario Pension Benefits Act.*

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries Standards of Practice applicable for December 31, 2016.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

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PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

However, there is limited data available to provide credible guidance on the cost of a purchase of partially indexed annuities in Canada. Furthermore, given the size of the Plan it may not be possible to settle the pensions via a single group annuity due to the limited availability of indexed and partially indexed annuities in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates between December 31, 2016 and December 30, 2017,* we have assumed that an appropriate proxy for estimating the cost of such purchase should be based on the yields on long-term Government of Canada Nominal Bonds and Real Return Bonds. The actual cost to settle the Plans benefits on wind-up could be materially different.

The Educational Note provides guidance on estimating the cost of annuity purchases assuming a typical group of annuitants. That is, no adjustments for sub- or super-standard mortality are considered. However, it is expected that insurers will consider plan experience and certain plan-specific characteristics when determining the mortality basis for a particular group. The Educational Note states that the actuary would be expected to make an adjustment to the regular annuity purchase assumptions where there is demonstrated substandard or super-standard mortality or where an insurer might be expected to assume so. In such cases, the actuary would be expected to make an adjustment to the mortality assumption in a manner consistent with the underlying annuity purchase basis. Given the uncertainty surrounding the actual mortality basis that would be typical of a group annuity purchase, it is reasonable to assume that there is a range of bases that can be expected not to be materially different from the actual mortality basis. Therefore, an adjustment to the regular annuity purchase assumptions would be warranted when the plan's assumed basis falls outside that range.

In this context, we have determined that no adjustment to the mortality rates used in the regular annuity purchase assumptions is required.

We have not included a provision for adverse deviation in the solvency and hypothetical wind-up valuations.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

The assumptions are as follows:

Form of Benefit Settlement Elected by Member

Lump sum:

Quebec members 100% of active members and deferred pensioners

Members of other 70% of active members under age 55 and 40% of active members over age

provinces 55 elect to receive their benefit entitlement in a lump sum

Annuity purchase: All remaining members are assumed to elect to receive their benefit

entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate

annuities from a life insurance company.

Basis for Benefits Assumed to be Settled through a Lump Sum

Mortality rates: 100% of the rates of the 2014 Canadian Pensioners Mortality

Table (CPM2014) with fully generational improvements using

CPM Scale B

Non-indexed interest rate: 2.20% per year for 10 years, 3.50% per year thereafter Partially-indexed (50%) interest rate: 1.60% per year for 10 years, 2.40% per year thereafter Partially-indexed (55%) interest rate: 1.60% per year for 10 years, 2.30% per year thereafter 1.60% per year for 10 years, 2.30% per year thereafter

Basis for Benefits Assumed to be Settled through the Purchase of an Annuity

Mortality rates: 100% of the rates of the 2014 Canadian Pensioners Mortality

Table (CPM2014) with fully generational improvements using

CPM Scale B

Adjustment to mortality rates: No adjustment Non-indexed interest rate: 3.16% per year

Partially-indexed (50%) interest rate: 1.54% Partially-indexed (55%) interest rate: 1.37%

Retirement Age

Maximum value: Members are assumed to retire at the age which maximizes the value of

their entitlement from the Plan based on the eligibility requirements which

have been met at the valuation date

Grow-in: The benefit entitlement and assumed retirement age of Ontario members

whose age plus service equals at least 55 at the valuation date, reflect their

entitlement to grow into early retirement subsidies and indexation benefits

Other Assumptions

Special payments: Discounted at the average interest rate of 2.94% per year

Final average earnings: Based on actual pensionable earnings and actual pensionable bonuses over

the averaging period

Family composition: Same as for going concern valuation

Maximum pension limit: \$2,914.44 increasing at 2.06% per year for 10 years, 3.17% per year

thereafter

Termination expenses: \$740,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Although the termination expense assumption is a best estimate, actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire and die consistent with the termination, retirement and mortality rates used for the going concern valuation;
- Pensionable earnings, the ITA pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions;
- · Active members accrue pensionable service in accordance with the terms of the Plan; and
- To accommodate for new entrants to the Plan, we have added to the projected liability an amount equal to the liability of new entrants that have joined the Plan in prior years.

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PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have valued those benefits that would have been paid had the Plan been wound-up on the valuation date, with the exception of certain benefits which may be excluded, as permitted by the Act. Specifically, future cost-of-living increases on pensions in payment were excluded from our calculation of solvency liabilities.

The solvency position is determined in accordance with the requirements of the Act.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

APPENDIX E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2016, provided by the Company.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

At December 31, 2016 there were 12 members who were terminated in 2016 and are on salary continuance until 2018. Their statistics are shown separately in the membership data summarized below.

	31.12.2016	31.12.2013		
Active and Disabled Members Accruing Defined Benefit Service (Non-SME)				
Number	2,060	2,117		
Total base earnings for the following year	\$174,312,200	\$168,382,000		
Average base earnings for the following year	\$84,600	\$79,500		
Average years of Non-SME DB pensionable service	10.2 years	10.6 years		
Average age	43.8 years	44.0 years		
Active and Disabled Members Accruing Defined Ben	nefit Service (SME)			
Number	33	39		
Total base earnings for the following year	\$7,060,100	\$8,045,700		
Average base earnings for the following year	\$213,900	\$206,300		
Average years of Non-SME DB pensionable service	5.8 years	8.2 years		
Average years of SME DB pensionable service	4.5 years	3.5 years		
Average age	49.8 years	49.8 years		
Suspended Defined Benefit Members Accruing Defined Contribution Service				
Number	39	55		
Total base earnings for the following year	\$3,580,400	\$4,880,400		
Average base earnings for the following year	\$91,800	\$88,700		
Average years of Non-SME DB pensionable service	7.5 years	6.2 years		
Average age	50.7 years	48.3 years		
Other Suspended Defined Benefit Members (Non-SMEs)				
Number	25	24		
Total base earnings for the following year	\$3,101,400	\$2,780,500		
Average base earnings for the following year	\$124,100	\$115,900		
Average years of Non-SME DB pensionable service	6.3 years	4.8 years		
Average age	42.7 years	37.8 years		
Other Suspended Defined Benefit Members (SMEs)				
Number	18	20		
Total base earnings for the following year	\$6,948,800	\$6,308,800		
Average base earnings for the following year	\$386,000	\$315,400		
Average years of Non-SME DB pensionable service	3.5 years	3.9 years		
Average years of SME DB pensionable service	1.5 years	1.3 years		
Average age	51.6 years	50.7 years		
Active Defined Contribution Members without Define	ed Benefit Service			
Number	101	156		
Total base earnings for the following year	\$9,048,800	\$13,388,700		
Average base earnings for the following year	\$89,600	\$85,800		
Average age	42.2 years	41.4 years		

	31.12.2016	31.12.2013
Suspended Defined Contribution Members without	Defined Benefit Serv	vice
Number	6	7
Total base earnings for the following year	\$841,600	\$838,000
Average base earnings for the following year	\$140,300	\$119,700
Average age	40.3 years	35.8 years
Deferred Pensioners		
Number	293	219
Total annual pension	\$1,917,400	\$1,012,600
Average annual pension	\$6,500	\$4,800
Average age	47.1 years	48.1 years
Pensioners and Survivors		
Number	1,741	1,554
Total annual lifetime pension	\$40,343,300	\$33,124,200
Average annual lifetime pension	\$23,200	\$21,300
Total annual temporary pension	\$2,068,200	\$2,033,600
Average annual temporary pension	\$6,300	\$6,700
Average age	72.4 years	72.1 years
Salary Continuance (With DB Service)		
Number	12	n/a
Total base earnings for the following year	\$1,413,000	
Average base earnings for the following year	\$117,700	
Average years of Non-SME DB pensionable service	18.3 years	
Average years of SME DB pensionable service	1.5 years	
Average age	56.0 years	

The membership movement in the DB and DC components of the Plan since the previous actuarial valuation is as follows:

	Active and Disabled Members Accruing DB Service	Suspended DB Members	Active and Disabled Members Accruing DC Service ¹²	Deferred Pensioners	Pensioners and Survivors	Salary Continuance	Total
Total at December 31, 2013	2156	99	163	219	1554	-	4,191
Adjustments	(1)	-	3	6	(3)	-	5
New entrants	384	-	22	-	-	-	406
Transfers							
 Transfers from DC to SME 	1	-	(1)	-	-	-	-
 Transfers from DB to DC 	(3)	3	-	-	-	-	-
 Transfers from DC to DB 	50	(8)	(42)	-	-	-	-
 SME transfer West to East 	3	(2)	-	-	-	-	1
 SME transfer East to West 	(2)	2	-	-	-	-	-
 Net to suspended status 	-	-	-	-	-	-	-
 Transfer Out to EI plan 	(12)	12	-	-	-	-	-
· Transfer In from El plan	6	(3)	-	-	-	-	3
Retirements							
 DB Retirements 	(207)	(6)	-	(31)	271	(27)	-
DC Retirements	-	-	(1)	-	-	-	(1)
Terminations of employment							
 Refunds & lump sum payments 	(101)	(5)	(34)	(37)	(1)	(13)	(191)
 Deferred pensions 	(129)	(4)	-	137	-	(4)	-
Non-vested	-		-	-	-	-	-
 Terminations not yet elected 	-	-	-	-	-	-	-
· Salary Continuance	(48)	(5)	(3)	-	-	56	-
Deaths							
· With further entitlement	(4)	(1)	-	(1)	(47)	-	(53)
 With no further entitlement 	-	-	-	-	(84)	-	(84)
 New survivors 	-	-	-	-	53	-	53
Guarantee expired	-	-	-	-	(2)	-	(2)
Total at December 31, 2016	2,093	82	107	293	1,741	12	4,328

¹² Includes active and disabled members accruing DC service with no DB service along with suspended DC members.

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

Distribution of Active and Disabled Non-SME DB Members Pensionable Base Earnings by Age Group and DB Pensionable Service

			Ye	ars of Pensi	onable Servi	ce			
Age	0-4	5-9	10-14	15-19	20-24	25-29	30-34	35+	Total
20 to 24	21								21
	\$65,136								\$65,136
25 to 29	148	26	1						175
	\$70,664	\$70,966	*						\$70,751
30 to 34	186	111	23						320
	\$77,533	\$81,172	\$84,756						\$79,314
35 to 39	152	83	69						304
	\$81,799	\$83,514	\$90,392						\$84,218
40 to 44	109	80	51	12	3				255
	\$82,504	\$85,458	\$87,646	\$101,634	\$92,263				\$85,282
45 to 49	82	73	65	20	22	9			271
	\$96,688	\$89,610	\$95,256	\$102,972	\$106,603	\$92,892			\$95,581
50 to 54	55	56	64	21	40	75			311
	\$81,390	\$88,390	\$83,809	\$83,162	\$86,682	\$89,167			\$85,824
55 to 59	29	41	33	21	39	46	42		251
	\$87,200	\$85,941	\$86,306	\$95,138	\$87,403	\$89,298	\$96,122		\$89,450
60 to 64	14	13	22	8	14	13	18	35	137
	\$87,692	\$71,745	\$88,530	\$80,652	\$79,937	\$91,910	\$82,982	\$84,092	\$83,972
65 to 69		2	3	1		2	3	3	14
		*	\$76,953	*		*	\$79,190	\$102,935	\$86,210
70+					1				1
					*				*
Total	796	485	331	83	119	145	63	38	2,060
	\$80,133	\$84,068	\$88,570	\$93,637	\$89,863	\$89,315	\$91,561	\$85,580	\$84,618

^{*} Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

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PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Distribution of Active and Disabled SME Members Pensionable Base Earnings by Age Group and DB Pensionable Service

			Year	s of Pensional	ble Service			
Age	0-4	5-9	10-14	15-19	20-24	25-29	30 +	Total
20 to 24								
25 to 29								
30 to 34			1					1
35 to 39		1	*					1
40 to 44	1	* 1	2					4
45 to 49	3	*	3	2	1			\$192,437 9
50 to 54	\$214,658 6	1	\$213,728 2	*	* 1	1		\$209,121 11
55 to 59	\$238,093 1	* 2	*	2	*	*		\$227,683 6
	*	*		*		*		\$227,799
60 to 64								
65 +	*							*
Total	12	5	8	4	2	2		33
	\$231,199	\$201,950	\$201,253	\$190,791	*	*		\$213,942

^{*} Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2016

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Distribution of Active and Disabled DC Members Pensionable Base Earnings by Age Group and Continuous Service

			Ye	ears of Pens	ionable Servi	ce			
Age	0-4	5-9	10-14	15-19	20-24	25-29	30-34	35+	Total
25 to 29	7	4							11
	\$74,988	\$81,163							\$77,234
30 to 34	5	12	7						24
	\$74,761	\$87,419	\$82,419						\$83,324
35 to 39	7	4	3	1					15
	\$68,067	\$66,658	\$82,528	*					\$72,802
40 to 44	1	2	11	3					17
	*	*	\$105,750	\$121,309					\$106,297
45 to 49	3	5	11	1	4	2			26
	\$124,991	\$81,241	\$109,311	*	\$120,455	*			\$105,941
50 to 54	1	6	4	2	1	10	1	1	26
	*	\$109,763	\$71,666	*	*	\$82,438	*		* \$88,018
55 to 59	1	1	2	2	1	4	1		12
	*	*	*	*	*	\$90,652	*		\$83,164
60 to 64	2		1	1	1	2			7
	*		*	*	*	*			\$102,941
65 to 69			2						2
			*						*
Total	27	34	41	10	7	18	2	•	140
	\$83,367	\$86,582	\$93,713	\$106,133	\$99,163	\$87,979	*	:	* \$90,209

^{*} Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

The distribution of the inactive members by age as at the valuation date is summarized as follows:

	Deferred F	Pensioners	Pensioners a	and Survivors
Age	Number	Average Pension	Number	Average Pension
Under 45	111	\$3,581	1	*
45 - 49	55	\$8,233	1	*
50 - 54	59	\$10,481	4	\$19,812
55 - 59	42	\$8,284	101	\$27,784
60 - 64	21	\$4,601	286	\$30,407
65 - 69	2	*	352	\$25,350
70 - 74			314	\$23,621
75 - 79			281	\$20,529
80 - 84			188	\$19,871
85 - 89	1	*	140	\$14,420
90 - 94			60	\$12,999
95+	2	*	13	\$8,057
Total	293	\$6,544	1,741	\$23,172

^{*} Cells with fewer than 3 members have been suppressed in order to preserve confidentiality

APPENDIX F

Summary of Plan Provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Enbridge Gas Distribution Inc. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2016. Since the previous valuation, the Plan has not been amended.

DB Component

The following is a summary of the main provisions of the DB component of the Plan in effect on December 31, 2016. This summary is not intended as a complete description of the Plan.

Background	The Plan became effective January 1, 1971.
	Benefits are based on a set formula and are entirely paid for by the Company.
	Effective July 1, 2001, the Plan was redesigned for all active or suspended members at that date. Prior to the redesign, participants in the DB component of the Plan accrued contributory credited service. Following the redesign, all active and suspended members were required to elect to participate in either the DB component or the DC component of the Plan for future service. Participants in the DB component of the Plan accrue non-contributory or SME credited service.
	In the future, members who are not SMEs may switch between the DB and DC components on the January 1 following the date they achieve 40 points or 60 points. Any changes will affect service after the decision point only. Members who are SMEs must participate in the DB component of the Plan.
Eligibility for Membership	New employees become members of the Plan immediately. They may elect to participate in either the DB or DC component of the Plan. SMEs must participate in the DB component.
Vesting	All members are vested immediately upon entering the Plan.
Employee Contributions	No employee contributions are required or permitted based on the current plan provisions. Prior to July 1, 2001, employee contributions were required.
Retirement Dates	Normal Retirement Date
	 The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday.
	Early Retirement Date
	• If a member has been in the Plan for at least two years, the member may choose to retire as early as age 55.

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2016

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Normal	Contributory Service:
Retirement Pension	2.0% of Final Five Year Average Earnings multiplied by years of contributory credited service;
	less
	100% of the Contributory Canada Pension Plan Entitlement.
	Non-Contributory Service:
	1.2% of Final Three Year Average Earnings multiplied by years of non-contributory credited service;
	less
	50% of the Non-Contributory Canada Pension Plan Entitlement;
	SME Credited Service:
	2.0% of Final Three Year Average Earnings multiplied by years of SME credited service.
Final Five Year Average Earnings	Final Five Year Average Earnings is calculated using the highest 60 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, including 50% of the actual bonus received for senior executive employees.
Final Three Year Average Earnings	Final Three Year Average Earnings is calculated using the highest 36 consecutive months of earnings received by the member in the 120 months immediately prior to termination or retirement, plus the sum of the highest three Pensionable Bonus payments made in the last five years divided by three.
	For Non-Contributory and SME Credited Service, Pensionable Bonus is defined as 50% of the sum of eligible performance bonuses.
Canada Pension	Contributory Service:
Plan Entitlement	One thirty-fifth of 25% of the lesser of the average earnings in the 60 months immediately preceding the date of exit and average of the YMPE in the five calendar years, including the current year, preceding the date of exit, multiplied by contributory credited service, to a maximum of 35 years.
	Non-Contributory Service:
	Calculated as if the member had reached age 65, multiplied by the ratio of the member's non-contributory credited service after the later of January 1, 1966 or age 18, to the number of years of possible CPP coverage to age 65, recognizing the permitted dropout period of 15%, and reduced by 6% per year for every year the retirement date precedes age 65, to a maximum reduction of 30%.

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Early Retirement Pension

The following benefits apply if a member retires early:

- If the member has attained age 60, the pension payable is as described above in the Normal Retirement section.
- If the member has 30 years of continuous Service or has attained age 60, the member is eligible for the benefits described in the previous paragraph plus, for contributory credited service, an additional benefit of a bridge pension payable to age 65 equal to 100% of the Contributory Canada Pension Plan Entitlement.
- If the member has not attained age 60 the member is also eligible, for noncontributory credited service, for an additional benefit of a bridge pension payable to age 60 equal to 50% of the Non-Contributory Canada Pension Plan Entitlement.
- If the member has not attained age 60 or 30 years of continuous service at retirement, an early retirement reduction of 5% per year is applicable from age 60 in respect of contributory and non-contributory credited service. For SMEs, the early retirement reduction is 3% per year for SME credited service. The reduction applies to the benefit described in the immediately preceding paragraphs including the bridge pensions.

Maximum Pension

The total annual pension payable from the Plan upon retirement, death or termination of employment cannot exceed the lesser of:

- 2% of the average of the best three consecutive years of total compensation paid to the member by Enbridge; and
- \$2,914.44, or such other maximum as may apply from time to time

indexed to the date of pension commencement, multiplied by his total credited Service and reduced for early retirement in accordance with the ITA rules.

Indexation of Pensions in Payment

On December 1 of each year a contractual cost of living increase equal to a percentage of the annual increase in the Consumer Price Index will apply to lifetime pensions in payment for at least one year. This percentage is 55% for contributory credited service and 50% for non-contributory and SME credited service. Indexation only applies to members that retire from active membership.

Prior to July 1, 2001, any increases to pensions in payment were on an ad-hoc basis.

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2016

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

Death Benefits	Death Before Eligible for Early Retirement
	If a member dies before he is eligible for early retirement benefits, the member's spouse, or beneficiary if there is no spouse, will receive a lump sum settlement equal to 100% of the commuted value of the member's reduced accrued pension deferred to age 55, in respect of all credited service.
	Death After Eligibility for Early Retirement
	If a member dies after his early retirement date and before his pension payments have begun, the member's spouse, or beneficiary if there is no spouse, will receive either a lump sum settlement or an immediate pension equal in value to 100% of the commuted value of the member's reduced accrued pension, in respect of all credited service.
	Death After Retirement
	The death benefit payable is in accordance with the form elected.
	The normal form of pension is a Joint and 60% Survivor annuity for members with a spouse and a life annuity with a 15-year guarantee period for single members.
Termination Benefits	If a member's employment terminates for reasons other than death or retirement, the member is entitled to their reduced accrued pension deferred to age 55. The Member has the option to transfer the value of the benefit to a locked-in RRSP.
Disability Benefits	Disabled members are eligible to retire at age 65. For members whose disability commenced before July 1, 2001 salary is assumed to increase with the Average Industrial Wage, while for members whose disability commences after July 1, 2001 salary is assumed to increase with inflation, subject to a maximum of 5% per year, to retirement. The disabled member continues to accrue credited service while disabled.

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2016

PENSION PLAN FOR THE EMPLOYEES OF ENBRIDGE GAS DISTRIBUTION INC. AND AFFILIATES

DC Component

The following is a summary of the main provisions of the DC component of the Plan in effect on December 31, 2016. This summary is not intended as a complete description of the Plan.

Background	The DC component of the Plan beca	ame effective July 1, 2001.
	Employer contributions are remitted with interest.	to individual member accounts and are credited
	Members receive the balance of the death or retirement.	ir individual employer account upon termination,
Eligibility for Membership	• •	of the Plan immediately. They may elect to mponent of the Plan. SMEs must participate in
Vesting	All members of the DC component v	rest immediately.
Employee Contributions	No employee contributions are requi	ired or permitted.
Employer	Employer contributions to the DC co	mponent are based on a member's points.
Contributions	· less than 40 points:	4.0% of pensionable earnings ¹³
	· 40 to 60 points:	5.5% of pensionable earnings
	- greater than 60 points:	7.0% of pensionable earnings
Maximum Contribution	The employer contributions are limit	ed to the amounts under the ITA.
Pensionable Earnings	Base salary plus 50% of actual bonu	us received.

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¹³ For members who were participating in the DC component of the Plan at June 30, 2001, the minimum employer contribution is 5.0% of pensionable DC earnings.

Filed: 2017-11-13, EB-2017-0086, Exhibit I.D1.EGDI.BOMA.28, Attachment 2, Page 31 of 31



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Filed: 2017-11-13, EB-2017-0086, Exhibit I.D1.EGDI.BOMA.28, Attachment 3, Page 2 of 19

HAXION MANAGEMENT OF THE PROPERTY OF THE PROPE

		December 31, 2015	December 31, 2016
Active DB Members	Number	2,109	2,060
(Non-SME)	Total base earnings	\$174,909,900	\$174,312,200
	Average base earnings	\$82,900	\$84,600
	Average years of Non-SME DB service	10.0 years	10.2 years
	Average age	43.4 years	43.8 years
Active DB Members	Number	38	33
	Total base earnings	\$8,301,800	\$7,060,100
	Average base earnings	\$218,500	\$213,900
	Average years of SME DB service	5.2 years	4.5 years
	Average age	51.4 years	49.8 years
Active DC Members	Number	165	140
	Total base earnings	\$15,028,800	\$12,629,200
	Average base earnings	\$91,100	\$30,200
	Average age	44.5 years	44.6 years
Suspended DB/DC	Number	49	49
Members	Total base earnings	\$10,810,400	\$10,891,800
	Average base earnings	\$220,600	\$222,300
	Average age	45.8 years	45.7 years

		December 31, 2015	December 31, 2016
Deferred	Number	249	293
Pensioners	Total annual pension	\$1,165,000	\$1,917,400
	Average annual pension	\$4,700	\$6,500
	Average age	46.9 years	47.1 years
Pensioners &	Number	1,682	1,741
Survivors	Total annual pension (incl. bridge)	\$37,550,100	\$40,343,300
	Average annual pension	\$22,300	\$23,200
	Average annual bridge	\$6,600	\$6,300
	Average age	72.4 years	72.4 years
Salary Continuance	Number	47	12
(with DB Service)	Total base earnings	\$5,028,800	\$1,413,000
	Average base earnings	\$107,000	\$117,700
	Average age	56.1 years	56.0 years
	Average years of Non-SME DB pensionable service	22.4 years	18.3 years
Salary Continuance	Zagaz		
(DC only)	Total base earnings	*	£ Z
	Average base earnings	*	\\\\\\
	Average age	49.8 years	

^{*} Cells with three or fewer members have been suppressed for confidentiality

Adjustments 1,274 127 249 1682 50 4342 184		Active DB	Suspended DB	Active DC	Deferreds	Pensioners & Survivors	Salary Continuance	
Adjustments 101 3 2 -1 New entrants 101 3 3 -1 Izansfers 1 1 -1 DC to SME Vest 1 2 -2 OC to SME East to West 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	cember 31,	2147	87	127	249	1682	20	
New entrants 101 3 Tiransfers -1 -1 DC to SME -1 -1 DB to DC -1 -1 SME west to store bed to Cto DB -1 -1 SME as to West -1 -1 Net to Suspended -1 -1 Net to Suspended -1 -1 Transfer to Let Dian -4 -4 Transfer to Let Dian -3 -1 Retirement -6 -7 DB Retirement -6 -7 Description -7 -7 Returned & LS -1 -6 -7 Deaths -1 -1 -1 Salary Continuance -6 -7 -1 Salary Continuance -6 -7 -1 With Further entitiesment -1 -1 -1 With no further entitiesment -1 -1 -1 New survivors -1 -1 -1 Claramine Experied	Adjustments				7			
Transfers -1 -1 DC to SME -1 -1 DC to DB -1 -1 SME West to East 1 2 -10 SME East to west 1 -1 -1 Net to Suspended 1 1 -1 Net to Suspended 1 1 -1 Net to Suspended 1 -1 -1 Transfer to El plan 4 4 4 Transfer to El plan 5 -1 -1 Retirement 7 -6 97 -27 DC Retirement 8 -6 -1 -1 Retirement 9 -6 -1 -1 -1 Retirement 9 -6 -7 -7 -7 Deferred 9 -8 -1 -1 -1 Salary Continuance 6 -6 -7 -1 -1 With Further entitlement 9 -6 -1 -1 -1 With no further entitlement 1 -1 -1 -1 -1 New survivors 1 -1 -1	New entrants	101		C				104
DC to SME 1 -1 DB to DC -1 1 SME West to East 2 -10 SME Sast to West -1 1 SME East to West -1 1 New to Suspended -1 -1 Transfer In From Elplan -4 4 Transfer In From Elplan -3 -1 Transfer In From Elplan -3 -1 Retirement -60 -4 -6 97 -27 DC Retirement -6 -1 -6 97 -7 -1 DC Retirement -6 -7 -1	Transfers							
DB to DC -1 1 DC to DB 12 -2 -10 SME West to East -1 -1 -1 Net to Suspended 1 -1 -1 Transfer In Victority to Eliplan -4 -4 -6 97 -27 Transfer In Four Eliplan -6 97 -6 -73	DC to SME							0
SME West to East 2 -10 SME East to West -1 -1 Net to Suspended 1 -1 Transfer Out to El plan -4 4 Transfer Out to El plan 3 -1 Transfer Out to El plan 3 -1 Transfer Out to El plan -4 4 Transfer In From El plan 3 -1 DB Retirement -6 97 DC Rotiromont -4 -1 LEmination -4 -1 Deferred -58 -1 Salay Continuance -6 97 Pending -7 -15 With Further entitlement -1 -15 New survivors -1 -15 Cuarantee Experied -1 -15 Adartantee Experied -1 -1 Adartantee Breakdown -1 -1 Adartantee Titlement) -1 -1 Adartantee Ryperied -1 -1 Adartantee Ryperied -1 </td <td>DB to DC</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td>0</td>	DB to DC							0
SME west to East 2 -1 Net to Suspended 1 -1 Net to Suspended 1 -1 Transfer lot Vit De El plan -4 4 Transfer In From El plan 3 -1 -6 97 -27 DB Retirement -6 97 -27 -27 DC Retirement -4 -4 -6 97 -27 DC Retirement -4 -4 -6 97 -27 DE Retirement -5 -1 -13 -4 -27 Salary Continuance -6 97 -13 -4 Salary Continuance -6 97 -13 With Further entitlement -1 -15 -4 With no further entitlement -1 -15 -4 New survivors -1 -15 -15 Beartifement -1 -15 -15 Marital Breakdown -1 -1 -1 Retirement -1 -1	DC to DB	12	7	-10				0
SME East to West -1 1 Net to Suspended 1 -1 Transfer Out to El plan 3 -1 Transfer In From El plan 3 -1 Retirement -6 97 -27 DC Retirement -6 97 -27 DC Retirement -6 97 -27 Refunds & LS -43 -1 -12 -15 -43 Refunds & LS -6 -7 -6 97 -27 Salary Continuance -6 -1 63 -4 -4 Salary Continuance -6 -1 63 -4 -4 With Further entitlement -1 -12 -15 -4 -4 With Further entitlement -1 -1 -13 -4 -4 With ruther entitlement -1 -1 -15 -4 -4 With ruther entitlement -1 -1 -1 -1 -4 -4 With ruther entitlement	SME West to East	2						
Net to Suspended 1 -1 -1 Transfer Out to El plan 3 -1 -6 97 -27 Retirement DB Retirement DC Retirement Immination Returned & LS -4 -6 97 -27 Perturned & LS -43 -1 -12 -15 -13 -4 Salary Continuance Pending Deaths -6 -15 -15 -4 -4 With Further entitlement New survivors -1 -12 -15 -4 -4 Guarantee Experied Ramital Breakdown -1	SME East to West							0
Transfer Out to El plan 4 4 Transfer In From El plan 3 -1 Retirement -60 -4 -6 97 -27 DB Retirement -60 -4 -6 97 -27 DC Retirement -60 -4 -6 97 -27 De Returds & LS -43 -1 -15 -13 -44 Salary Continuance -6 -15 -15 -44 -4 With Further entitlement -1 -15 -15 -4 -4 With no further entitlement -1 -15 -15 -4 -4 With no further entitlement -1 -15 -15 -15 -4 New survivors -1 -1 -15 -15 -1 -4 Guarantee Experied -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1 -1	Net to Suspended							0
Transfer In From El plan 3 -1 -6 97 -27 DB Retirements -60 -4 -6 97 -27 DC Retirement -43 -1 -15 -13 -13 Deferred -58 -1 63 -4 -4 Salary Continuance -6 -1 63 -4 -6 With Further entitlement -1 -15 -4 -6 -4 With no further entitlement -1 -1 -15 -4 -6 -4 With no further entitlement -1 -1 -1 -15 -4 -4 With no further entitlement -1 -1 -15 -1	Transfer Out to El plan	7 -	4					0
Retirement DB Retirements -6 97 -27 DC Retirement DC Retirement DC Retirement DC Retirement S LS	Transfer In From El plan	က						7
DR Retirement Solution -60 -4 -6 97 -27 DC Retirement Solutionation -43 -1 -12 -15 -13	Retirement							
DC Retirement A3 -1 -12 -15 -13 Refunds & LS -3 -1 -15 -13 Deferred -58 -1 63 -4 Salary Continuance -6 - 6 Pending -1 (14) (14) With Further entitlement -1 (14) (14) With no further entitlement (36) (15) 15 Remsion Paid (retirement) (1) (1) Marital Breakdown (1) (1)	DB Retirements	09-	-		9	26	-27	0
Termination Refunds & LS -43 -1 -15 -13 -14 -13 -14 -1	DC Retirement							0
Refunds & LS -43 -1 -15 -13 Deferred -58 -1 63 -4 Salary Continuance -6 -7 63 -4 Pending -1 -1 -4 6 With Further entitlement -1 (14) (14) Vith no further entitlement (36) (36) (15) New survivors	Termination							
Deferred -58 -1 63 -4 Salary Continuance -6 -7 6 Pending -1 (14) 6 With Further entitlement -1 (14) (14) Vith no further entitlement -4 6 Vith no further entitlement -4 6 Vith no further entitlement -4 14) New survivors -4 -4 Guarantee Experied -4 -4 Guarantee Experied -4 -4 Pension Paid (retirement) -4 -4 Marital Breakdown -1 -4 Marital Breakdown -1 -4 Amounted Breakdown -1 -4 Amounted Breakdown -1 -4 Amounted Breakdown -1 -4 Amounted Breakdown -1 -1 Amounted Breakdown -1 -1 Breakdown -1 -1 Breakdown -1 -1 Breakdown <t< td=""><td>Refunds & LS</td><td>-43</td><td></td><td></td><td>-15</td><td></td><td>-13</td><td>(84)</td></t<>	Refunds & LS	-43			-15		-13	(84)
Salary Continuance -6 6 Pending -1 (14) (14) With Further entitlement -1 (36) 15 Vith no further entitlement -1 15 New survivors -15 15 Guarantee Experied (1) (1) Marital Breakdown (1) (1)	Deferred	-28			63		4	0
Pending Deaths With Further entitlement With no further entitlement Vith no further entitlement New survivors Guarantee Experied Guarantee Experied Fension Paid (retirement) Marital Breakdown (1) (14) (14) (14) (15) (15)	Salary Continuance	9					9	0
Deaths-1(14)With Further entitlement-1(36)Vith no further entitlement15New survivors15Guarantee Experied(1)Pension Paid (retirement)(1)Marital Breakdown(1)	Pending							0
With Further entitlement-1(14)Vith no further entitlement(36)New survivors15Guarantee Experied(1)Pension Paid (retirement)(1)Marital Breakdown(1)	Deaths							
Vith no further entitlement(36)New survivors15Guarantee Experied(1)Pension Paid (retirement)(1)Marital Breakdown(1)	With Further entitlement					(14)		(15)
New survivors Guarantee Experied Pension Paid (retirement) Marital Breakdown (1)	With no further entitlement					(36)		(36)
Guarantee Experied Pension Paid (retirement) Marital Breakdown	New survivors					15		15
Guarantee Experied Pension Paid (retirement) Marital Breakdown								0
Pension Paid (retirement) Marital Breakdown	Guarantee Experied					(1)		
	Small Pension Paid (retirement)					(1)		(1)
	Marital Breakdown							

As of December 31, 2016 © MERCER 2017

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	2016
January 1, 2016	\$944.8
PLUS:	
Current service contributions	
Special payment contributions	
Investment income	7.07
	2.07\$
Pensions paid	7.7
Lump-sums paid	
Expenses	2.0
	\$20.6
December 31, 2016	\$964.9
Rate of return* gross	2.7%
Rate of return* net	7.04%

^{*} Calculated assuming middle of period cash flows

PLAN STATISTICS - SERP ALL MEMBERS

		December 31, 2015	December 31, 2016
Suspended	Number		
	Total base earnings	*	¥ Z
	Average base earnings	*	¥ Z
	Average years of SERP service	12.8 years	
	Average age	63.5 years	4
Deferred	Number		
Pensioners	Total annual pension	*	*
	Average annual pension	*	*
	Average age	58.1 years	59.1 years
Pensioners and	Number	56	2
Survivors	Total annual lifetime pensions	\$1,000,225	\$1,062,544
	Average annual lifetime pension	\$38,500	\$39,400
	Average age	72.6 years	73.2 years

^{*} Cells with three or fewer members have been suppressed for confidentiality

PLAN STATISTICS -SSERP ALL MEMBERS

		December 31, 2015	December 31, 2016
Pensioners and	Number	4	
Survivors	Total annual lifetime pensions	\$399,600	\$402,000
	Average annual lifetime pension	006,66\$	\$100,500
	Average age	76.6 years	77.6 years

MANUEL POR STANDARY SERVICE SE

There was one retirement from suspended in the SERP

- There were no member movements in the SSERP during 2016
- Count as of December 31, 2016
- Pensioners & Survivors: 4

Count as of December 31, 2016

- Deferred Pensioners: 1

- Pensioners & Survivors: 27

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	RCA Fund	RCA Tax	Lotal
January 1, 2016	4.6\$	9.7\$	\$17.0
PLUS:			
Current service contributions			
Special payment contributions			
Net transfers from CRA	Sign	(0.5)	
Investment income			
	6.0\$	(\$0.2)	20.7
·SSH			
Pensions paid			
Expenses			
	81.0	5	81.0
December 31, 2016	\$9.3	\$7.4	\$16.7
Rate of return gross	2.58%	%00'0	4.15%
Rate of return net	7.48%	%0000	4.10%

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	EBP Fund	RCA Fund	RCA Tax	Total
January 1, 2016	\$2.1	\$3.3	\$2.8	\$8.1
SOL				
Special payment contributions				
Net transfers from CRA		(0.1)		
Investment income	0.0	0.3		0.4
	\$0.1	\$0.2	\$0.1	\$0.4
·SSU				
Pensions paid	6.0			9.0
Expenses				
	\$0.3	\$0.1	'	\$0.4
December 31, 2016	81.9	\$3.4	\$2.8	\$8.1
Rate of return gross	%98'_	2.70%	%0000	2.00%
Rate of return net	7.81%	7.64%	%000.0	4.97%



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	Current Valuation	Previous Valuation
Discount rate	EGD RPP – 5.75% SERP, SSERP – 3.20%	EGD RPP – 5.50% SERP, SSERP – Same
Inflation	2.00%	Same
Salary increases	2.50% + age based merit & promotion scale	2.50% + age based merit & promotion scale
Target bonus	SME: Actual bonus Non-SME: 12% non-union, 5% union	Same
Bonus load	135% of target	Same
ITA limit / YMPE increases	2.50%	Same

	Current Valuation	Previous Valuation
Mortality table	2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	Same
Mortality improvements	Fully generational using CPM Improvement Scale B (CPM-B)	Same
Retirement rates	Age related table	Same
Termination rates	Age related table	Same
Disability rates	None	Same
Eligible spouse at retirement	%08	Same
Spousal age difference	Male 3 years older	Same
DB/ DC choice	Continue in current component	Same

		Current Valuation	Previous Valuation
Non	n-indexed interest rates		
•	Benefits settled through lump sum ¹	2.20% for 10 years, 3.50% thereafter	2.10% for 10 years, 3.70% thereafter
Ш О.	Benefits settled through annuity purchase	3.16%	3.08%
Parti	rtially-indexed interest rates		
	Benefits settled through lump sum	1.60% for 10 years, 2.40% thereafter (50% indexed)	1.70% for 10 years, 2.80% thereafter (50% indexed)
		1.60% for 10 years, 2.30% thereafter (55% indexed)	1.70% for 10 years, 2.70% thereafter (55% indexed)
•	Benefits settled through annuity purchase	1.54% (50% indexed), 1.37% (55% indexed)	1.52% (50% indexed), 1.36% (55% indexed)
Settle	telement option		
	Benefits settled through lump sum ¹	EGD RPP – 70% of active members under age 55, 40% of active members over age 55	Same
		SERP/SSERP – 100% of members	
Ф	Benefits settled through annuity purchase	All remaining members	Same
14000/			

¹ 100% of Quebec active members and deferred pensioners are assumed to elect a lump su

	Current Valuation	Previous Valuation
Mortality	CPM 2014 Combined table with generational mortality improvements (Scale CPM-B)	Same
Retirement age		
 Maximum value 	Optimal age	Same
Grow-in (Ontario members only)	Grow-in to early retirement subsidies, bridge and indexation benefit if age plus service >=55	Same
ITA maximum pension limit	\$2,914.44 increasing at 2.06% for 10 years, 3.17% thereafter to assumed retirement age	\$2,890.00 increasing at 1.82% for 10 years, 2.88% thereafter to assumed retirement age
Final average earnings	Actual pensionable earnings and bonus history	Same
Family composition	Same as for going concern valuation	Same
Termination expenses	EGD RPP – \$740,000 SERP – \$50,000 SSERP – \$50,000	EGD RPP – \$730,000 SERP – Same SSERP – Same
Benefits excluded from solvency valuation (EGD RPP only)	Future cost of living adjustments	Same

or for not unding for Enbridge Inc. to present preliminar intended to facilitate Enbridge Inc. de report may not be used or relied upon Mercer has prepared this report exclusively for Enbridge Inc. to present prelimina December 31, 2016 valuation. This report is intended to facilitate Enbridge Inc. de December 31, 2016 funding valuation. This report may not be used or relied upor other purpose; Mercer is not responsible for the consequences of any such other modified, incorporated into or used in other material, sold or otherwise provided, other person of entity, without Mercer's permission.

repo understanding reference All parts of this report, including any documents incorporated by reference, are integ explaining its contents; no part may be taken out of context, used or relied upon with as a whole.

forma $\boldsymbol{\omega}$ for substitute $\boldsymbol{\omega}$ not S The results presented herein are preliminary and subject to change. This report valuation report. Decisions about benefit changes, granting new benefits, investment policy, fundin and/or benefit-related issues should not be made solely on the basis of this prelim careful consideration of alternative economic, financial, demographic and societal scenarios that assume future sustained investment losses.

adverse concern for any, tore going margin, Enbridge Inc. is responsible for selecting the plan's funding policy (including the deviations in the going concern valuation), the actuarial and asset valuation metly valuation, and methodologies affecting the solvency valuation.

estimate The actuarial assumptions used in the going concern valuation reflect the actuary's the margin for adverse deviations which has been selected by Enbridge Inc. Enbrid reviewing the going concern valuation assumptions referenced and advising Merce deems worthy of consideration in the determination of such assumptions. the ma

range from scenario included To prepare the results in this report, actuarial assumptions are used to model a single possibilities for each valuation basis. The results based on that single scenario are inchanced for each valuation and the plan's actual experience will differ from those differences may be significant or material. Different assumptions or scenarios within the may also be reasonable, and results based on those assumptions would be different.

expect changes Of because Furthermore, actuarial assumptions may be changed from one valuation to the next kregulatory and professional requirements, developments in case law, plan experienca about the future and other factors.

are Mercer has used and relied on the membership data as supplied by Enbridge Inc. sufficient and reliable for its intended purpose, the results of our calculation may dresults that would be obtained with such data. Although Mercer has reviewed the intended use in accordance with accepted actuarial practice in Canada, Mercer has the data or information provided. Statistics on, and reconciliation of the member presentation and Appendix.

conld interpretations Mercer has used and relied on the plan documents, including amendments, and interprovisions supplied are not accurate provisions, supplied by Enbridge Inc. If any plan provisions supplied are not accurate results of any calculation may differ significantly from the results that would be obtain complete information. Moreover, plan documents may be susceptible to different interprecould be reasonable, and the results of estimates under each of the different interpre

uston audit. for information ut further We used financial data submitted by Enbridge Inc. as of the valuation date witho this information would not be verified by a plan's actuary. We have reviewed the consistency and general reasonableness.

legal substi Funding calculations reflect our understanding of the requirements of Ontario's legislatior and related regulations that are effective for the current plan year as of the valuation date engaged in the practice of law or tax advice. This report does not constitute and is not a tax advice.

and Enbridge Inc. is solely responsible for selecting the plan's investment policies, asset investments.

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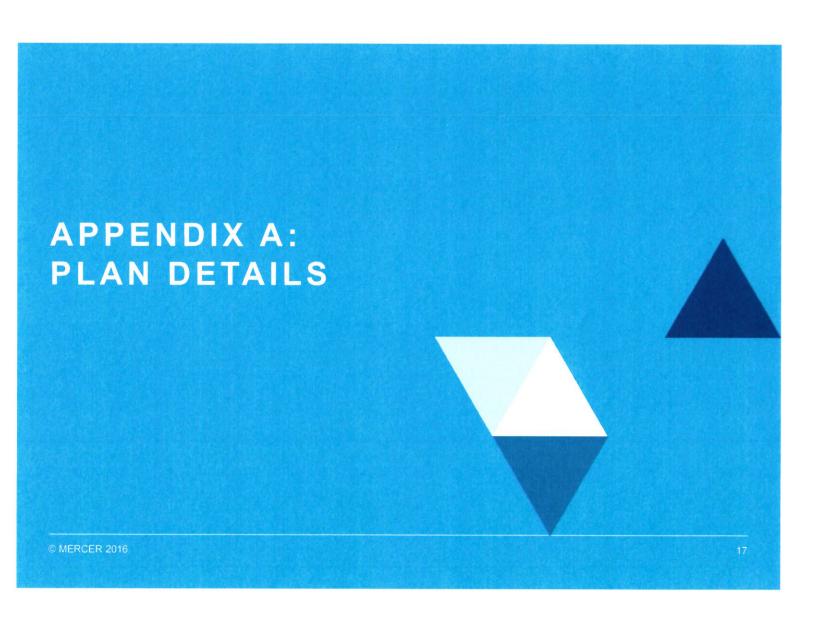


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PLAN STATISTICS - EI RPP ACTIVE MEMBERS

		December 31, 2015	December 31, 2016
Active DB Members	Number	3,105	2,801
(Non-SME)	Total base earnings	\$344,343,300	\$314,865,600
	Average base earnings	\$110,900	\$112,400
	Average years of Non-SME DB service	5.3 years	5.9 years
	Average age	40.4 years	40.7 years
Active DB Members	Number	181	166
(SME)	Total base earnings	\$46,037,100	\$43,054,100
	Average base earnings	\$254,300	\$259,100
	Average years of SME DB service	5.4 years	5.8 years
	Average age	50.1 years	50.1 years
Active DC Members	Number	353	247
	Total base earnings	\$37,794,400	\$25,969,200
	Average base earnings	\$107,100	\$105,100
	Average age	37.6 years	37.7 years
Suspended DB/DC	Number	91	198
Members	Total base earnings	\$16,355,000	\$24,361,200
	Average base earnings	\$179,700	\$123,000
	Average age	46.7 years	42.9 years

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PLAN STATISTICS - EI RPP INACTIVE MEMBERS

		December 31, 2015	December 31, 2016	
Deferred	Number	445	530	
Pensioners	Total annual pension	\$2,993,400	\$3,750,800	
	Average annual pension	\$6,700	\$7,100	
	Average age	42.1 years	42.6 years	
Pensioners & Survivors	Number	640	744	
	Total annual pension (incl. bridge)	\$16,521,000	\$19,047,800	
	Average annual pension (incl. bridge)	\$25,800	\$25,600	
	Average age	68.7 years	67.7 years	

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MEMBERSHIP RECONCILIATION EI RPP

			Active and			
	Active and Disabled		Suspended DC			
	Members Accruing	Suspended DB	Members (without	Deferred	Pensioners and	
N 1 D 04 0045	DB Service	Members	DB Service)	Pensioners	Survivors	Total
Number at December 31, 2015	3286	80	364	445	640	4815
Adjustment						
New entrants	154		11			165
New entrants - Transfers from EGD	5					5
Transfers						
Transfers from DC to SME						
Transfers from SME to DC						
 Transfers from DB to DC 						
Transfers from DC to DB	27	1	(28)			0
SME transfer West to East						
SME transfer East to West						
Net to suspended status	(3)	3				0
Transfer out (ESO members)	(120)	120	(39)			(39)
Retirements						
DB Retirements	(89)	(16)		(12)	117	0
DC Retirements			(2)	,		(2)
T						
Terminations of employment	(404)	(0)	(40)	(00)		(0.40)
Refunds and lump sum payments	(131)	(2)	(43)	(66)		(242)
Deferred pensions	(157)	(4)		161		0
Death						
With further entitlement	(3)				(6)	(9)
With no further entitlement	(2)				(14)	(16)
New survivors				2	7	9
Pending death						
Number at December 31, 2016	2967	182	263	530	744	4686

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ASSET RECONCILIATION (\$000,000'S) EI RPP - DB ASSETS

	2016	
January 1, 2016	\$730.8	
PLUS:		
Company's contributions		
 Current service, including expense allowance 	51.5	
 Special payments, including transfer deficiency payments 	21.3	
Investment income	62.1	
	\$134.9	
LESS:		
Pensions paid	17.4	
Lump-sum refunds	16.9	
Investment expenses	2.7	
Non-investment expenses	1.5	
	\$38.5	
December 31, 2016	\$827.2	

Rate of return* gross	8.30%
Rate of return* net of investment expenses	7.92%

^{*} Calculated assuming middle of period cash flows

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PLAN STATISTICS - EI SPP

		December 31, 2015	December 31, 2016
Active Members (SME only)	Number	222	200
	Total base earnings	\$55,030,900	\$50,236,200
	Average base earnings	\$247,900	\$251,200
	Average years of DB service	9.0 years	9.1 years
	Average age	50.5 years	50.1 years
Suspended Members (SME only)	Number	10	7
	Total base earnings	\$3,175,000	\$2,032,400
	Average base earnings	\$317,500	\$290,300
	Average years of DB service	6.9 years	4.4 years
	Average age	50.4 years	47.7 years
Deferred Pensioners	Number	21	21
	Total annual pension	\$224,100	\$248,400
	Average annual pension	\$10,700	\$11,800
	Average age	50.4 years	50.7 years
Pensioners and Survivors	Number	104	129
	Total annual pension	\$6,515,100	\$7,707,200
	Average annual pension	\$62,600	\$59,700
	Average age	66.8 years	65.6 years

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MEMBERSHIP RECONCILIATION EI SPP

	Active and Disabled Members Accruing			Pensioners and	
	(SME Only)	(SME Only)	Deferred Pensioners	Survivors	Total
Number at December 31, 2015 (RCA)	213	4	20	102	339
Number at December 31, 2015 (CGT)	9	6	1	2	18
Number at December 31, 2015	222	10	21	104	357
Adjustment				1	1
New entrants	8				8
Promotions to SME	7				7
Demotions from SME	(5)				(5)
Transfers from US					
 Suspended members 					
Transfers to US					
Transfers to Canada	1	(1)			0
Transfer from Enbridge	(1)	1			0
Retirements					
• SMEs	(19)	(3)	(1)	23	0
Non SMEs	2	. ,		3	3
SMEs without supplemental benefits	(2)				(2)
Terminations of employment					
 Deferred pensions (SMEs) 	(5)		5		0
Deferred pensions (Non SMEs)					
SMEs without supplemental benefits	(2)		(1)		(3)
Refunds and lump sum payments	(4)		(3)		(7)
Death					
With further entitlement				(1)	(1)
With no further entitlement				(2)	(2)
New survivors				1	1
Number at December 31, 2016 (RCA)	192	3	19	124	339
Number at December 31, 2016 (CGT)	8	4	2	5	18
Number at December 31, 2016	200	7	21	129	357

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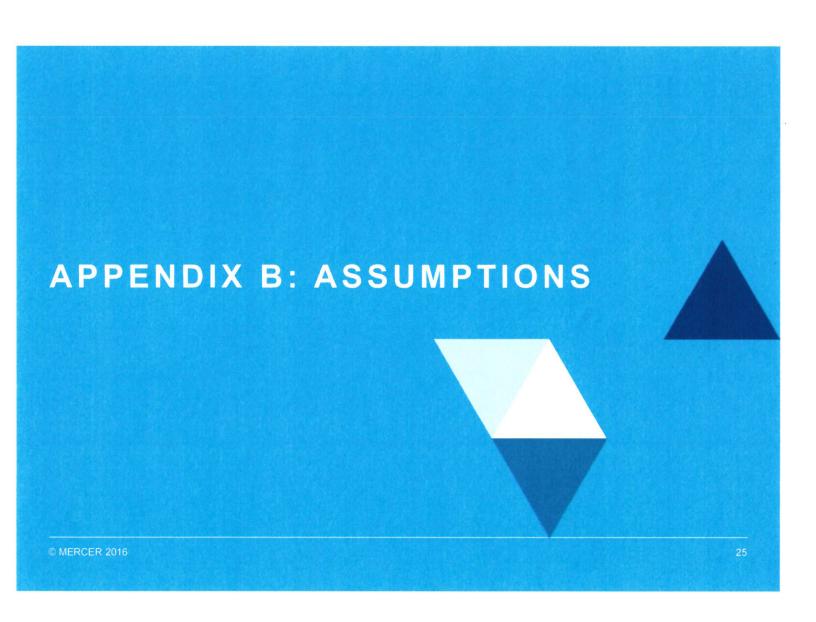
ASSET RECONCILIATION (\$000,000'S) EI SPP

	201	6
	RCA	CGT
January 1, 2016	\$196.7	\$14.6
PLUS:		
Company's contributions		
Current service	0.0	0.4
Special payments	0.0	0.1
Investment income	16.9	1.1
	\$16.9	\$1.6
LESS:		
Pensions paid	6.2	1.1
Lump-sum refunds	1.7	0.0
Expenses	0.5	0.0
	\$8.4	\$1.1
December 31, 2016	\$205.2	\$15.1

Rate of return* gross	8.83%	8.66%
Rate of return* net	8.54%	8.37%

^{*} Calculated assuming middle of period cash flows

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SUMMARY OF GOING CONCERN ASSUMPTIONS ECONOMIC ASSUMPTIONS

	Proposed Assumption	Previous Valuation
Discount rate	EI RPP – 5.95% EI SPP – 5.25%	EI RPP – 6.20% EI SPP – 5.40%
Administration expenses	EI RPP – \$1,750,000	EI RPP – \$1,750,000
Inflation	2.00%	2.00%
Salary increases	2.50% + age based merit & promotion scale	Same
Target bonus	SME: Actual bonus Non-SME: 12%	Same
Bonus load	135% of target	Same
ITA limit / YMPE increases	2.50%	Same

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SUMMARY OF GOING CONCERN ASSUMPTIONS DEMOGRAPHIC ASSUMPTIONS

	Proposed Assumption	Previous Valuation
Mortality table	2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	Same
Mortality improvements	Fully generational using CPM Improvement Scale B (CPM-B)	Same
Retirement rates	Age related table	Same
Termination rates	Age related table	Same
Disability rates	None	Same
Eligible spouse at retirement	80%	Same
Spousal age difference	Male 3 years older	Same
DB/DC choice	Continue in current component	Same

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SOLVENCY / HYPOTHETICAL WIND-UP METHODS & ASSUMPTIONS

	Current Valuation	Previous Valuation		
Non-indexed interest rates				
Benefits settled through lump sum ¹	2.20% for 10 years, 3.50% thereafter	2.10% for 10 years, 3.70% thereafter		
Benefits settled through annuity purchase	3.21%	3.13%		
Partially-indexed interest rates (50%)				
Benefits settled through lump sum ¹	1.60% for 10 years, 2.40% thereafter	1.70% for 10 years, 2.80% thereafter		
Benefits settled through annuity purchase	1.56%	1.54%		
Settlement option				
Benefits settled through lump sum	EI RPP – 70% of active members under age 55, 50% of active members over age 55 EI SPP – 100% of members	Same		
Benefits settled through annuity purchase	All remaining members	Same		

¹ El SPP rates grossed up for tax

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SOLVENCY / HYPOTHETICAL WIND-UP METHODS & ASSUMPTIONS

	Current Valuation	Previous Valuation
Mortality	CPM 2014 Combined Table with generational mortality improvements (Scale CPM-B)	Same
Retirement age		
Maximum value	Optimal age	Same
ITA maximum pension limit	\$2,914.44 increasing at 2.06% for 10 years, 3.17% thereafter to assumed retirement age	\$2,890.00 increasing at 1.82% for 10 years, 2.88% thereafter to assumed retirement age
Final average earnings	Actual pensionable earnings and bonus history	Same
Family composition	Same as for going concern valuation	Same
Termination expenses	EI RPP – \$2,900,000 EI SPP – \$230,000	EI RPP - \$2,760,000 EI SPP - \$160,000

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IMPORTANT NOTICES

Mercer has prepared this report exclusively for Enbridge Inc. to present preliminary funding results for the December 31, 2016 valuation. This report is intended to facilitate Enbridge Inc. decision making relating to the December 31, 2016 funding valuation. This report may not be used or relied upon by any other party or for any other purpose; Mercer is not responsible for the consequences of any such other use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used or relied upon without reference to the report as a whole.

The results presented herein are preliminary and subject to change. This report is not a substitute for a formal valuation report.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this preliminary valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

Enbridge Inc. is responsible for selecting the plan's funding policy (including the margin, if any, for adverse deviations in the going concern valuation), the actuarial and asset valuation methods in the going concern valuation, and methodologies affecting the solvency valuation.

The actuarial assumptions used in the going concern valuation reflect the actuary's best estimate, except for the margin for adverse deviations which has been selected by Enbridge Inc. Enbridge Inc. is responsible for reviewing the going concern valuation assumptions referenced and advising Mercer as to any information it deems worthy of consideration in the determination of such assumptions.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different.

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IMPORTANT NOTICES

Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

Mercer has used and relied on the membership data as supplied by Enbridge Inc. If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided. Statistics on, and reconciliation of the membership data are provided in the presentation and Appendix.

Mercer has used and relied on the plan documents, including amendments, and interpretations of plan provisions, supplied by Enbridge Inc. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

We used financial data obtained from CIBC Mellon's online application Workbench, as of the valuation date without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and general reasonableness. These results will be updated based on Enbridge Inc.'s audited financial statements when they become available.

Funding calculations reflect our understanding of the requirements of Federal legislation, the Income Tax Act and related regulations that are effective for the current plan year as of the valuation date. Mercer is not engaged in the practice of law or tax advice. This report does not constitute and is not a substitute for legal or tax advice.

Enbridge Inc. is solely responsible for selecting the plan's investment policies, asset allocations and individual investments.

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Exhibit I.D1.EGDI.BOMA.29

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Plus Attachments

BOMA INTERROGATORY #29

INTERROGATORY

Ref: Mercer Report, p2

- (a) Please provide a copy of the Ontario Minister of Finance's proposed reforms to the funding framework for Ontario registered deferral benefit pension plans.
- (b) Have the details of the proposed reform been made available? If so, please provide them. Please provide a copy of the 2015 Quebec registered deferral benefit plan reforms.
- (c) Please provide the impact of each of EGD's June 2, 2017 proposed changes (effective January 1, 2018), summarized in Appendix B, Tables 1, 2 and 3, on EGD's 2018 forecast accrued expenses, and forecast cash requirements.
- (d) Please show separately the impact on EGD's forecast 2018 accrued expenses and cash requirements from the proposed changes flowing from EGD's regular review of its pension investments (first bullet on p2 of Mercer Report), and the changes that would flow from the Ontario reform proposals, once they have been adopted into law.
- (e) Have the Ontario reform proposals been incorporated in legislation/regulation yet? If not, when is it likely that they will become law?
- (f) If the Ontario proposed reforms are not yet law, why is EGD proposing to make changes in its funding (cash contributions) prior to the legal requirement to do so?
- (g) With respect to adjustments proposed due to EGD's regular review of its pension plan investments, are they done annually? What aspects of the plans are reviewed annually, other than expected returns and discount rates? Why are changes proposed to both expected returns and discount rates? Please show the impact the modifications to the expected returns and discount rates have on EGD's annual accrual expenses and funding obligations in 2018.
- (h) Please provide a copy of the ASC 715 (MS GAAP) Actual Valuation Report as of December 31, 2016.
- (i) Are EGD's May and June 2017 assumptions likely to be revised prior to January 2018? What is the likely impact, directionally, and in order of magnitude, on the forecast 2018 accrued expenses and cash requirements? Does EGD intend to

Witnesses: Mercer

Exhibit I.D1.EGDI.BOMA.29

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Plus Attachments

make any changes to its forecast requirements as a result of any revisions to the June assumptions? Please discuss.

(j) Preamble:

"The EGD RRP projections are based on the assumption that a new valuation will be filed at December 31, 2017, and that EGD would contribute the minimum amounts prescribed under the new Ontario framework, which we have assumed would be the same as those prescribed by the Supplemental Pension Plan Act and Regulations of Quebec (the "Quebec SPPA")". (Mercer, p5)

Does EGD intend to file a revised actual valuation by December 31, 2017 with the FSO and the CRA? Why would it finalize payments pursuant to an Act that is not yet in force? Why does Mercer made the assumptions described in the quote above?

<u>RESPONSE</u>

- a) Attached are the Ontario Ministry of Finance's May 19, 2017 announcements (I.D1.EGDI.BOMA.29_Attachment 1.pdf and I.D1.EGDI.BOMA.29_Attachment 2.pdf)
- b) A summary of the key funding reforms are:
- Going-Concern Funding: Requiring funding on an enhanced going concern basis which includes:
 - shortening the amortization period from the current 15 years to 10 years for funding a shortfall in the plan, and the consolidation of the special payments into a single schedule; and,
 - funding of a reserve within the plan, called a Provision for Adverse Deviation or PfAD.
- **Solvency Funding:** Requiring funding on a solvency basis to the extent that a plan's funded status falls below 85% (from current 100%).

Benefit Improvements and Contribution Holidays: Providing funding rules for benefit improvements and restricting contribution holidays to improve benefit security.

Witnesses: Mercer

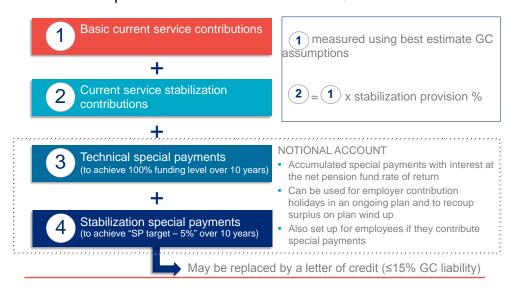
Exhibit I.D1.EGDI.BOMA.29

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Plus Attachments

While further details are not yet available, in particular for the PfAD, the funding reforms in Ontario appear to be aligned with those recently adopted in Quebec, with the 85% solvency funding "floor" being a key difference.

Attached is a copy of Quebec's Bill 57, An Act to amend the Supplemental Pension Plans Act mainly with respect to the funding of defined benefit pension plans (I.D1.EGDI.BOMA.29_Attachment 3.pdf).

The main components of contributions under Quebec rules can be summarized as follows:



where the stabilization provision (SP) target percentage is based on two factors as set out in the table below:

SP Target %	Asset / Liability Duration Ratio				
% of Variable Income Securities	0%	25%	50%	75%	100%
0%	12	10	8	6	5
20%	14	12	10	8	6
40%	16	14	12	10	8
50%	17	15	13	11	9
60%	19	17	15	13	11
70%	22	20	18	16	14
80%	24	22	20	18	18
100%	27	25	23	21	20

Witnesses: Mercer

Exhibit I.D1.EGDI.BOMA.29

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Plus Attachments

c) The impact of reflecting each of EGD's June 2, 2017 proposed changes (effective January 1, 2018), summarized in Appendix B of the Mercer report (Exhibit D1, Tab 5, Schedule 1, Appendix 1, Pages 11 to 13) is a reduction to EGD's 2018 forecast accrual expense by \$0.05 million, and a reduction to EGD's 2018 forecast cash requirement by \$1.40 million.

d) Impact of Changes in Asset Allocations: The impact from the investment mix changes flowing from the pension investment review is a reduction to EGD's 2018 forecast accrual expense by \$5.08 million, and a reduction to EGD's 2018 forecast cash requirement by \$2.07 million.

Impact of Changes in Funding Framework: The impact from the anticipated changes to the Ontario funding framework is an increase to EGD's 2018 forecast accrual expense by \$0.06 million, and a reduction to EGD's 2018 forecast cash requirement by \$17.68 million.

- e) The Ontario reform proposals have not yet been incorporated into legislation. The Ministry of Finance announcement earlier this year stated that the government intends to introduce legislation in the fall of 2017 to enable the announced changes.
- f) EGD is not proposing to make changes to its funding (cash contributions) prior to the legislative authority to do so. EGD will continue to fund the pension plan based on current legislation and the latest filed valuation report until the next valuation report is filed. However, EGD expects the funding reforms will be passed into law in the fall of 2017 and the most likely outcome is that EGD will file a new valuation report on or before September 30, 2018 with an effective date of December 31, 2017. Upon filing of a new valuation report, a true-up would be made for any difference between amounts contributed prior to the filing and amounts set out in the new report. Thus, EGD's best estimate of 2018 funding is based on the proposed funding reforms.
- g) EGD typically conducts a formal review of its pension plan asset mix approximately every three to five years.

All economic and demographic assumptions that affect the cost of the plans are reviewed annually.

Accounting discount rates (i.e., those summarized on page 4 of the Mercer Report and used in the measurement of forecasted accrual expense) are based on market yields on high-quality corporate bonds. The yields on such bonds are sensitive to changes in the underlying economic environment and therefore change frequently (sometimes significantly). Changes are proposed to accounting discount rates in order to capture the most recent information regarding market yields on high-quality corporate bonds.

Witnesses: Mercer

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The accounting discount rates are not affected by the proposed modifications to pension plan asset mix.

Funding discount rates (i.e., the rate of 6.00% for the EGD RPP on page 7 of the Mercer Report, which is used in the determination of forecasted cash requirement) are based on long-term best estimates of a pension plan's net investment return, less a margin for adverse deviation. Funding discount rates depend on a plan's target asset allocation, expectations regarding capital markets, and expected plan expenses. Changes are proposed to the EGD RPP funding discount rate in order to capture proposed changes to the plan's target asset mix (these changes were subsequently approved and adopted by Enbridge in their Statement of Investment Policies and Procedures as well as current capital market expectations). Please refer to the response to part (d) of this Interrogatory for the impact that the modifications to the pension plan asset mix have on forecasted cash requirements.

The expected return on asset assumptions (i.e., those summarized on page 3 of the Mercer Report and used in the measurement of forecasted accrual expense) are based on management's best estimate of long-term net investment return. Expected return on assets assumptions depend on a plan's target asset allocation, expectations regarding capital markets, and expected plan expenses. Changes are proposed to the expected return on assets assumptions in order to capture proposed changes (subsequently approved and adopted as noted earlier) to the pension plans' target asset mixes, as well as current capital market expectations. Please refer to the response to part (d) of this Interrogatory for the impact that the modifications to the pension plan asset mix have on accrual expense.

h) Attached is the requested report (I.D1.EGDI.BOMA.29_Attachment 4.pdf).

The forecasts are not updated as they employed the best available information at the time they were prepared. Under EGD's current custom IR plan, there is a variance account to capture any variance between actual accrual based pension and OPEB costs versus forecasts in rates. The actual 2018 accrual based pension costs are finalized in January 2018.

i) Based on information known today, the most likely outcome is that EGD will file a new valuation report with FSCO and CRA with a valuation effective date of December 31, 2017. That valuation would reflect funding rules that are in force at that time (it is expected that the new funding rules will be enacted in the fall of 2017). EGD's contributions for 2018 will most likely then be based on the funding requirements set out in that new valuation report

Witnesses: Mercer

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To provide a best estimate of EGD's contributions for 2018, Mercer made assumptions based on the best information available including the most likely filing scenario and anticipated funding reforms.

Witnesses: Mercer



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Making Workplace Pension Plans More Sustainable

Province Helping Businesses Compete While Protecting Retirement Security May 19, 2017 10:00 A.M.

Ontario is moving forward with changes that will help ensure workers' retirement benefits are protected and maintained, while enabling business to grow and be more competitive.

Changes will help keep defined benefit pension plans healthy and sustainable. Employers will continue to be required to ensure pension funds are appropriately funded and to pay into a reserve to protect benefits for workers and retirees. In addition, employers will also be required to make additional contributions should the plan's funded status fall below a certain level. Employers will have greater flexibility in managing their pension contributions, allowing them to plan for their pension costs more easily. There will be no impact on the pensions that retirees now receive as a result of these changes.

Along with new funding requirements, additional measures will protect benefit security for plan members and retirees. The monthly guarantee provided by the Pension Benefits Guarantee Fund will be increased by 50 per cent, from \$1,000 a month to \$1,500 a month.

The government intends to introduce legislation in the fall to enable these changes and will be consulting on the details of new regulations.

Helping businesses maintain their workplace pension plans while protecting benefit security for workers and retirees is part of our plan to create jobs, grow our economy and help people in their everyday lives.

QUOTES

- "Everyone deserves a secure retirement. By providing more flexibility, defined benefit pension plans will remain a vital part of our retirement income system in Ontario. With these changes, we are also ensuring that pension plans are affordable for businesses and benefit security for workers and retirees is protected."
- Charles Sousa Minister of Finance
- " CARP commends the Ontario government for its continued focus on improving financial security for retirees. With unprecedented gains in longevity and historically low interest rates,

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defined benefit pension plans have experienced significant challenges in recent years. We all BOMA.29 Attachment 1 pleased to see that the government has taken a balanced approach to funding reform by providing welcome relief to plan sponsors while also improving plan security for pension recipients."

- Wanda Morris

Vice-President, Advocacy and COO, Canadian Association of Retired Persons

"With these modernized pension rules, the government is directly helping Ontario's business community stay competitive. The changes provide employers with greater flexibility within the funding rules without impacting the current benefits earned by workers and received by retirees, or the security of these benefits."

- Winston Woo

Chair of the Finance & Tax Committee, Canadian Manufacturers and Exporters

QUICK FACTS

- These reforms will help protect the almost one million Ontarians that rely on defined benefit pension plans for income in their retirement.
- Defined benefit pension plans provide retirees with regular payments calculated based on factors such as length of service and salary levels.
- The Pension Benefits Guarantee Fund is unique among Canadian jurisdictions and requires employers to make regular contributions to the fund to protect pension benefits in the rare event an employer goes bankrupt and its pension plan is underfunded.
- In 2016, the government consulted on how Ontario should modernize the funding framework for defined benefit pension plans, and received more than 90 submissions.

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Strengthening and Modernizing Workplace Pensions May 19, 2017 10:00 A.M.

The government is implementing a new framework for defined benefit pension plans. The changes will help ensure retirement income security for workers and retirees is protected while helping keep workplace pension plans affordable, enabling Ontario businesses to grow and compete.

Highlights of the new funding framework for defined benefit pension plans include:

- Requiring funding on enhanced going concern basis; changes to the going concern funding rules include shortening the amortization period from 15 years to 10 years for funding a shortfall in the plan and consolidating special payment requirements into a single schedule.
- Requiring funding of a reserve within the plan, called a Provision for Adverse Deviation or PfAD. This reserve will help manage future risk and help ensure benefits are secure.
- Requiring funding on a solvency basis in the event that a plan's funded status falls below 85 per cent (based on the Financial Services Commission of Ontario's most recent estimates, 15 per cent of plans would still need to fund on this basis under the new regime).

To help ensure benefit security in the event that a pension plan is not fully funded and the employer is bankrupt, the government will be increasing the monthly guarantee provided by the Pension Benefits Guarantee Fund for a plan member's pension by 50 per cent, to \$1,500 from \$1,000.

Additional complementary changes include:

- Providing a discharge of liabilities when annuities are purchased for retirees or deferred plan members, providing greater income security for individuals.
- Providing funding rules for benefit improvements and restricting contribution holidays to improve benefit security.
- Increasing transparency by requiring plans to develop funding and governance policies and ensuring beneficiaries receive updated information on the status of their plan.

The government will be moving forward with a review of the rules governing the wind-up of defined benefit pension plans and studying a proposal to establish an agency to administer pension benefits of wound-up plans on an ongoing basis.

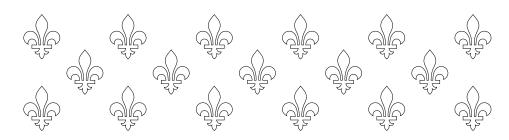
As an interim step, measures will be implemented in the coming weeks to assist defined benefit plans that are required to file valuation reports dated on or after December 31, 2016 and before December 31, 2017. These measures will assist plans that would otherwise face new solvency funding requirements due to those filings.

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NATIONAL ASSEMBLY

FIRST SESSION

FORTY-FIRST LEGISLATURE

Bill 57 (2015, chapter 29)

An Act to amend the Supplemental Pension Plans Act mainly with respect to the funding of defined benefit pension plans

Introduced 11 June 2015 Passed in principle 4 November 2015 Passed 26 November 2015 Assented to 26 November 2015

EXPLANATORY NOTES

This Act amends the Supplemental Pension Plans Act mainly to establish a new method for funding defined benefit pension plans by replacing the solvency method by one based on funding.

It provides for the establishment of a stabilization provision whose level will be determined in the manner prescribed by regulation, including by using a scale to be applied in accordance with, in particular, the investment policy of the pension plan. The provision will be composed of actuarial gains, special current service contributions and special amortization payments.

Pension plans will be required to adopt a funding policy that meets the requirements prescribed by regulation.

The Act amends the rules for appropriating and allocating surplus assets during the life of a plan and in the event of termination of the plan. Surplus assets may not be appropriated to the payment of contributions or of additional obligations arising from an amendment to the plan nor be transferred to the employer unless the plan is funded, the target level of the stabilization provision has been exceeded by five percentage points and the degree of solvency of the plan is at least 105%. The surplus assets must first be appropriated to the payment of employer and member current service contributions. Up to 20% of any remaining surplus assets may, in accordance with the plan's provisions, be appropriated to the payment of the additional obligations arising from an amendment to the plan or the payment of member contributions or be transferred to the employer.

Employer contributions that are technical amortization payments or stabilization amortization payments, except those paid by letter of credit, must be monitored separately. These amounts will be used to determine, in the event of surplus assets, the maximum amount of the surplus that can be appropriated to the payment of employer contributions.

Under the Act, an actuarial valuation must be carried out every three years. However, if the funding level determined in an actuarial valuation is less than 90%, the plan must be the subject of annual actuarial valuations until the funding level reaches at least 90%. Furthermore, an annual notice on the financial position of the plan

must be sent to the Régie des rentes du Québec within four months after the end of every fiscal year of the plan.

Asset smoothing is allowed, but the averaging period cannot exceed five years.

Additional obligations arising from an amendment to a pension plan will be payable in a lump sum if the plan's funding level is below 90%. Otherwise, such obligations may be funded over a maximum period of five years.

The test for minimum employer contributions is amended by making it possible to distinguish between current service contributions and amortization payments if part of the latter is assumed by the members; however, a member's current service contributions may not be used to fund more than 50% of the value of the member's pension benefits.

The requirement to include the additional pension benefit is removed for all pension plans.

The benefits of members whose active membership ends, except in the case of members and beneficiaries who are required to transfer their benefits without having the option of maintaining them in the plan, are paid according to the degree of solvency of the plan, without residual benefits. For pension plans with an annuity purchasing policy that meets the requirements prescribed by regulation, payment of all or part of the pension benefit in accordance with that policy can constitute final payment of the benefits paid.

The Act allows variable benefits to be paid, as for a life income fund, under a plan's defined contribution provisions.

The Act also contains miscellaneous, consequential and transitional provisions to facilitate the implementation of the measures it proposes.

LEGISLATION AMENDED BY THIS ACT:

- Supplemental Pension Plans Act (chapter R-15.1).

Bill 57

AN ACT TO AMEND THE SUPPLEMENTAL PENSION PLANS ACT MAINLY WITH RESPECT TO THE FUNDING OF DEFINED BENEFIT PENSION PLANS

THE PARLIAMENT OF QUÉBEC ENACTS AS FOLLOWS:

SUPPLEMENTAL PENSION PLANS ACT

- **1.** Section 14 of the Supplemental Pension Plans Act (chapter R-15.1) is amended
- (1) by inserting the following subparagraph after subparagraph 9 of the second paragraph:
- "(9.1) whether or not the members contribute to amortization payments and, if applicable, the method for calculating them;";
- (2) by inserting the following subparagraph after subparagraph 12 of the second paragraph:
- "(12.1) if applicable, the powers under which the pension committee is authorized to make the final payment of all or part of the benefits of a member or beneficiary by purchasing an annuity from an insurer under the conditions provided for by the plan's annuity purchasing policy, and the rules applicable to such a payment;";
- (3) by replacing subparagraphs 16, 16.1 and 17 of the second paragraph by the following subparagraphs:
- "(16) the conditions and procedure for allocating surplus assets or, in the case of a pension plan to which Chapter X applies, the balance of surplus assets referred to in the third paragraph of section 230.2, in the event of termination of the plan;
- "(17) in the case of a pension plan to which Chapter X applies, the conditions and procedure for appropriating all or part of the balance of surplus assets referred to in the third paragraph of section 146.8, either to the payment of the value of the additional obligations arising from an amendment to the plan, to the refund of member contributions or to the transfer of amounts to the employer or to a combination of those appropriation methods and, if applicable, the nature of the amendments that may be the object of such an appropriation;

- "(18) in the cases referred to in section 146.9.2, the conditions and procedure for appropriating all or part of the surplus assets, either to the payment of employer contributions, to the payment of the value of additional obligations arising from an amendment to the plan or to a combination of these appropriation methods and, if applicable, the nature of the amendments that may be the object of such an appropriation."
- **2.** Sections 21.1 to 21.3 of the Act are repealed.
- **3.** Section 26 of the Act is amended
- (1) by replacing the second item of the list in subparagraph 2 of the first paragraph by the following item:
- "—an amendment to the plan pertaining to the appropriation or allocation of surplus assets;";
 - (2) by striking out the first sentence of the third paragraph;
 - (3) by replacing "In addition, where" in the third paragraph by "Where";
- (4) by replacing "il" in the third paragraph in the French text by "le présent article".
- **4.** Section 33 of the Act is amended by inserting "or to the plan's annuity purchasing policy established in accordance with Division II.1 of Chapter XI" after "section 98" in the third paragraph.
- **5.** The Act is amended by inserting the following before section 37:

"DIVISION I

"TYPE OF CONTRIBUTIONS".

- **6.** Section 38 of the Act is amended
- (1) by adding, at the end, "and, in the case of a plan to which Chapter X applies, to establish a stabilization provision, determined in accordance with section 125, in respect of those obligations";
 - (2) by adding the following paragraph at the end:
- "The part of the current service contribution intended to establish the stabilization provision is to be called a current service stabilization contribution."
- **7.** The Act is amended by inserting the following sections after section 38:
 - **"38.1.** The following are amortization payments:

- (1) the technical amortization payment, intended to amortize the unfunded actuarial liability determined in accordance with section 131;
- (2) the stabilization amortization payment, intended to amortize the unfunded actuarial liability determined in accordance with section 132; and
- (3) improvement amortization payments, intended to amortize any unfunded actuarial liability determined in accordance with section 134.
- **"38.2.** The special improvement payment is a payment that, in respect of the additional obligations arising from an amendment to the pension plan, must be paid in accordance with section 139.
- **"38.3.** The special annuity purchasing payment is a payment that may be required on a payment of benefits made in accordance with the annuity purchasing policy and that, if applicable, must be calculated and paid in accordance with the provisions provided for in section 142.4."
- **8.** The Act is amended by inserting the following before section 39:

"DIVISION II

"PAYMENT OF CONTRIBUTIONS".

- **9.** Section 39 of the Act is amended by replacing subparagraphs a and b of subparagraph 2 of the first paragraph by the following subparagraphs:
- "(a) the current service contribution determined in accordance with sections 128 and 129;
- "(b) the sum of the amortization payments determined for the fiscal year and the special improvement payments payable during the fiscal year."
- **10.** Section 39.1 of the Act is amended by adding the following paragraph at the end:

"The agreement referred to in subparagraph 3 of the first paragraph is not required if the contribution reduction is less than or equal to the sum of the current service stabilization contribution and the stabilization amortization payment."

- **11.** Section 41 of the Act is amended by replacing "a special amortization payment" in the first paragraph by "a special improvement payment".
- **12.** Section 42 of the Act is amended by adding "in relation to that liability" after "the amortization payment determined".
- **13.** Section 42.1 of the Act is replaced by the following sections:

"42.1. Under the conditions prescribed by regulation, an employer may, on providing the pension committee with a letter of credit established in accordance with the regulation, be relieved of paying all or part of the portion of the employer contribution determined for the current fiscal year of the pension plan in respect of the stabilization amortization payment payable during the year.

The total amount of such letters of credit may not exceed 15% of the liabilities of the plan, determined on a funding basis.

"42.2. Employer contributions that are technical amortization payments or stabilization amortization payments, except those paid by letter of credit, must be the subject of special monitoring. Employer contributions paid in excess of the contributions required must be included as well.

Member contributions that are technical amortization payments or stabilization amortization payments must also be the subject of special monitoring.

Interest on those contributions, at the rate of return obtained on the investment of the plan assets, reduced by the investment and administration fees, must be included as well."

14. Section 60 of the Act is amended

- (1) by inserting "described in section 38" in the first paragraph after "member contributions";
 - (2) by inserting the following paragraph after the first paragraph:

"In addition, if the member contributes to amortization payments, the member's member contributions, with accrued interest, reduced by the excess contributions calculated in accordance with the first paragraph may not be used to pay more than the value referred to in that paragraph.";

- (3) by striking out subparagraph 7 of the second paragraph.
- **15.** Section 60.1 of the Act is repealed.
- **16.** Section 61 of the Act is amended by replacing "sections 60 and 60.1 apply" in the first paragraph by "section 60 applies".
- **17.** Section 86 of the Act is amended by striking out "as well as the value of the additional pension under section 60.1" in subparagraph 1 of the second paragraph.
- **18.** The Act is amended by inserting the following division after section 90:

"DIVISION III.1

"VARIABLE BENEFITS

- **"90.1.** A pension plan that includes defined contribution provisions may allow a member who has ceased to be an active member or, on the death of such a member, the member's spouse to elect to receive variable benefits from the funds the member or spouse holds under the defined contribution provisions, on the conditions and within the time prescribed by regulation."
- **19.** Section 118 of the Act is replaced by the following section:
 - "118. Every pension plan must be the subject of an actuarial valuation
 - (1) at the date on which it becomes effective;
- (2) no later than at the date of the end of the last fiscal year of the plan occurring within three years after the date of the last complete actuarial valuation of the plan;
- (3) at the date of the agreement with the insurer for the purposes of a payment of benefits made in accordance with the plan's annuity purchasing policy;
- (4) in the case of an amendment having an impact on the funding of the plan, at the date determined under section 121;
- (5) at the date of the end of the fiscal year of the plan that precedes a fiscal year in which surplus assets are appropriated to the payment of employer contributions under section 146.8; or
 - (6) whenever required by the Régie, at the date set by the Régie.

If an actuarial valuation referred to in subparagraph 2 of the first paragraph determines that the degree of solvency of the plan is less than 90%, the plan must be the subject of a complete actuarial valuation not later than the end date of the following fiscal year and the end date of each subsequent fiscal year, until the degree of solvency reaches at least 90%.

An actuarial valuation required under the first or second paragraph must be complete. However, the valuations required under subparagraphs 3, 4 and 5 of the first paragraph may be partial, but only if, in the case of a valuation referred to in subparagraph 4 or 5, the date of the valuation corresponds to the date of the end of the fiscal year of the plan and no complete actuarial valuation is required under this Act or by the Régie at that date."

20. Section 119 of the Act is amended

(1) by inserting the following subparagraph before subparagraph 1 of the first paragraph:

- "(0.1) not later than the expiry of the time granted under section 25 for filing the application for registration of the plan in the case of an actuarial valuation required under subparagraph 1 of the first paragraph of section 118;";
- (2) by replacing "subparagraph 2 of the first paragraph" in subparagraph 1 of the first paragraph by "subparagraph 2, 4 or 5 of the first paragraph or the second paragraph";
- (3) by inserting the following subparagraph after subparagraph 1 of the first paragraph:
- "(1.1) within four months after the date of the actuarial valuation in the case of an actuarial valuation required under subparagraph 3 of the first paragraph of that section;";
- (4) by replacing "subparagraph 3" in subparagraph 2 of the first paragraph by "subparagraph 6".
- **21.** The Act is amended by inserting the following section after section 119:
- "119.1. If, at the date of the end of a fiscal year of the pension plan, no actuarial valuation is required under subparagraph 2 of the first paragraph of section 118, the pension committee must send the Régie, no later than four months after that date, a notice informing it of the financial position of the pension plan at that date.

The information to be contained in the notice and the attestations and documents to be included with it are prescribed by regulation.

Any certification required for the purposes of the notice must be carried out in accordance with the first paragraph of section 122, which applies with the necessary modifications."

22. Section 121 of the Act is amended

- (1) by replacing "last actuarial valuation" in subparagraphs 1 and 2 of the first paragraph by "end of the last fiscal year";
 - (2) by adding the following paragraph at the end:

"However, an amendment resulting in a reduction of the obligations of the plan must be considered for the first time at the date it becomes effective."

- **23.** The Act is amended by inserting the following sections after section 122:
- "122.1. For the purposes of this chapter, the assets and liabilities of a pension plan are both reduced by an amount corresponding to the sum of the following values:

- (1) the value of any additional voluntary contributions paid into the pension fund, with accrued interest;
- (2) the value of the contributions paid into the pension fund under provisions which, in a defined benefit plan, are identical to those of a defined contribution plan, with accrued interest;
- (3) the value of amounts received by the pension plan following a transfer, even otherwise than under Chapter VII, with accrued interest.

However, in the case of a floor plan, the assets and liabilities of a plan are not to be reduced by the value referred to in subparagraph 2.

- "122.2. For the purposes of this chapter, the letters of credit provided by the employer under section 42.1 that may be considered in the plan's assets cannot exceed 15% of the liabilities of the plan."
- **24.** The Act is amended by replacing Divisions II, III and IV of Chapter X, comprising sections 123 to 142, by the following:

"DIVISION II

"FUNDING

- "§1.—Determination of funding
- "123. For the purpose of determining the funding level of a pension plan at the date of an actuarial valuation, the plan's liabilities must be equal to the value of the obligations arising from the plan taking into account the service credited to the members.

A pension plan is funded if, at the date of the actuarial valuation, the plan's assets are equal to or greater than its liabilities.

- **124.** For the sole purpose of establishing the level of funding of a pension plan at the date of an actuarial valuation,
- (1) the plan's assets must be increased by the special improvement payment prescribed in section 139; and
- (2) the plan's liabilities must be increased by the value of the additional obligations arising from any amendment to the plan considered for the first time at the date of the valuation, calculated on the assumption that the effective date of the amendment is the valuation date.

The funding level of a pension plan at the date of the actuarial valuation is the percentage that the plan's assets are of its liabilities.

- **"125.** Every pension plan must provide for the establishment of a stabilization provision whose target level is determined in the manner prescribed by regulation, in particular by using a scale that is to be applied according to certain criteria, including the target set out in the plan's investment policy in effect at the date of each actuarial valuation required under section 118.
- "126. The funding method used in an actuarial valuation must be consistent with generally accepted actuarial principles and be based on the assumption that the pension plan is perpetual.

The actuarial assumptions and methods used to determine the funding level of a plan must be suited, in particular, to the type of plan concerned, its obligations and the position of the pension fund.

- **"127.** The method for smoothing the market value of the assets of the pension plan may not level the short-term fluctuations in that value over a period exceeding five years.
- **"128.** The current service contribution must be equal to or greater than the sum of
- (1) the value of the obligations arising from the pension plan in respect of credited service completed over the course of the fiscal year or the part of the fiscal year referred to in paragraph 1 of section 140; and
- (2) the value of the stabilization provision in respect of those obligations, according to the target level determined in accordance with section 125.

The contribution may, however, be less if it is determined using a method which, at all times, keeps the plan partially funded or fully funded at the required funding level by adding the plan stabilization provision target level less five percentage points.

"129. The value of the obligations referred to in sections 123, 124 and 128 which, under the plan, are to increase according, in particular, to the progression of the members' remuneration must include the estimated amount of those obligations when they become payable, assuming that contingencies based on actuarial assumptions as to survival, morbidity, mortality, employee turnover, eligibility for benefits or other factors will occur.

Furthermore, any pension benefit increase provided for by the plan which becomes effective after the benefits begin to be paid must be taken into account in determining that value.

"§2.—Funding deficiencies

"130. There are three types of funding deficiencies: the technical actuarial deficiency, the stabilization actuarial deficiency and the improvement unfunded actuarial liability.

- **"131.** The technical actuarial deficiency corresponds, at the date of an actuarial valuation, to the amount by which the plan's liabilities exceed its assets, increased by the value of any amortization payments remaining to be paid to amortize any improvement unfunded actuarial liability determined in a prior actuarial valuation.
- **"132.** The actuarial stabilization deficiency corresponds, at the date of an actuarial valuation, to the amount by which the plan's liabilities, reduced by the technical actuarial deficiency determined in accordance with section 131 and increased by the value of the stabilization provision target level less five percentage points, exceed its assets, increased by the value of the amortization payments remaining to be paid to amortize any improvement unfunded actuarial liability determined in a prior actuarial valuation.
- **"133.** The interest rate used to establish the value of the improvement amortization payments referred to in sections 131 and 132 is the same as the one used to establish the liabilities of the plan.
- "**134.** An improvement unfunded actuarial liability corresponds, at the date of an actuarial valuation, to the value of the additional obligations arising from any amendment to the plan, except for the amendment referred to in section 139, considered for the first time in the valuation, increased by the value of the stabilization provision target level in respect of those obligations and reduced, if applicable, by the amount corresponding to the part of the value of those obligations that is paid for by appropriation of the plan's surplus assets.
- "135. The amortization payments that, if applicable, remain to be paid in relation to any improvement unfunded actuarial liability determined in a prior actuarial valuation may only be eliminated if, at the date of the actuarial valuation, the assets of the pension plan are equal to or greater than its liabilities, increased by the value of the stabilization provision target level less five percentage points.
- "§3.—Amortization of funding deficiencies
- **136.** Every funding deficiency must be amortized by dividing it into as many amounts as there are full months included in the amortization period.
- "137. The monthly amortization payable for any fiscal year of the pension plan, and any part of such a fiscal year, included in the amortization period must be established as a set amount at the date the unfunded actuarial liability is determined. However, if the members contribute to amortization payments, the monthly payments may represent an hourly rate or a rate of the remuneration of or a percentage of the total payroll for the active members; the rate or percentage must be uniform unless it is established by reference to a variable authorized by the Régie.

- "**138.** The amortization period for an unfunded actuarial liability begins at the date of the actuarial valuation in which the unfunded liability is determined. It expires at the end of a fiscal year of the pension plan that ends
- (1) no later than 10 years after the date of the valuation, if the liability is a technical actuarial deficiency;
- (2) no later than 10 years after the date of the valuation, if the liability is a stabilization actuarial deficiency; or
- (3) no later than five years after the date of the valuation, if the liability is an improvement unfunded actuarial liability.

"§4. — Special improvement payment

"139. If the actuarial valuation used to determine the value of the additional obligations arising from an amendment to the pension plan shows that the plan's funding level, determined without reference to the amendment, is less than 90%, a special improvement payment equal to the value of the additional obligations, at the date of the valuation, increased by the value of the stabilization provision target level in respect of those obligations, must be paid into the pension fund.

The special improvement payment is payable in full as of the day following the date of the valuation.

"§5.—Miscellaneous provisions

- **"140.** In addition to the other elements prescribed by regulation, an actuarial valuation must determine
- (1) the current service contribution, expressed in currency or as a rate or percentage of the remuneration of active members, for the fiscal year or the part of the fiscal year of the pension plan that immediately follows the date of the valuation and for every fiscal year that follows until the date of the next actuarial valuation to which it is subject under subparagraph 2 of the first paragraph of section 118;
- (2) the total amount of the current service contribution and the amount of the part of that contribution referred to in subparagraph 2 of the first paragraph of section 128;
 - (3) the plan's assets and liabilities;
- (4) the amount of each deficiency and that of the related amortization payment; and
 - (5) the amounts recorded under section 42.2.

"DIVISION III

"SOLVENCY

"**141.** For the purpose of determining the solvency of a pension plan at the date of an actuarial valuation, the plan's assets must be established according to their liquidation value, or an estimate of that value, and be reduced by the estimated amount of the administration costs to be paid out of the pension fund, assuming that the pension plan is terminated on the valuation date.

The pension plan's liabilities must be equal to the value of the obligations arising from the plan, assuming that the plan is terminated on the valuation date.

A pension plan is solvent if its assets are equal to or greater than its liabilities.

- **"142.** For the sole purpose of establishing the degree of solvency of a pension plan at the date of an actuarial valuation,
- (1) the plan's assets must be increased by the special improvement payment prescribed in section 139; and
- (2) the plan's liabilities must be increased by the value of the additional obligations arising from any amendment to the plan considered for the first time on the date of the valuation, calculated on the assumption that the effective date of the amendment is the valuation date.

The degree of solvency of a pension plan at the date of an actuarial valuation is the percentage that the plan's assets are of its liabilities.

"142.1. If the plan expressly provides that the amount of a member's pension is to be established with reference to the progression of the member's remuneration after termination, the value of the pension must be established assuming that the plan is terminated in such circumstances that the benefits accrued to the member in respect of the pension must be estimated at their maximum value. If the plan provides for other obligations whose value depends on the circumstances in which the plan is terminated, they must be included in the liabilities to the extent provided in the scenario used for that purpose by the actuary in charge of the valuation.

If the liabilities established in accordance with subparagraph 2 of the first paragraph of section 142 and with the first paragraph of this section are less than the value of the obligations arising from the pension plan, assuming that the plan is terminated on the valuation date in such circumstances that the benefits accrued to the members must be estimated at their maximum value, the valuation report must also indicate the latter value.

"142.2. The liabilities of a pension plan under which refunds or benefits are guaranteed by an insurer must, for the purpose of determining the plan's

solvency, include the value corresponding to those benefits, and the plan's assets must include an amount equal to that value.

"142.3. The values referred to in subparagraph 2 of the first paragraph of section 142 and in section 142.1 are determined by applying sections 211 and 212 and subparagraph 1 of the second paragraph of section 212.1, with the necessary modifications. In the case of pensions already in payment, inasmuch as they are not guaranteed by an insurer at the valuation date, those values must be determined according to an estimation of the premium that an insurer would charge to guarantee the pensions at the valuation date.

"DIVISION III.1

"FUNDING RELATING TO ANNUITY PURCHASING POLICY

"142.4. A payment of benefits made in accordance with the annuity purchasing policy of a pension plan must meet the funding requirements prescribed by regulation.

If those requirements are not met, a special annuity purchasing payment, calculated in the manner determined by regulation, must be paid as prescribed in that regulation.

"DIVISION IV

"FUNDING POLICY

- "142.5. The person or body who may amend the pension plan must establish a written funding policy that meets the requirements prescribed by regulation, review it regularly and send it to the pension committee without delay."
- **25.** Section 143 of the Act is amended by replacing "Régie." at the end by "Régie or, if the degree of solvency is more recent, in the notice prescribed by section 119.1 sent to the Régie. A pension plan may however provide that the 100% limit does not apply or establish a limit of more than 100%."
- **26.** Section 146 of the Act is amended by adding, at the end, ", in the following cases:
- (1) the member or beneficiary does not have the option of maintaining his benefits in the pension plan;
- (2) the plan provides for the payment of the value of members' and beneficiaries' benefits in a proportion that is greater than the degree of solvency of the plan".

27. The Act is amended by replacing Divisions I and II of Chapter X.1, comprising sections 146.1 to 146.9, by the following:

"DIVISION I

"PROVISIONS OF THE PENSION PLAN

- **"146.1.** Surplus assets may, during the life of a pension plan, be appropriated to the refund or payment of benefits or the payment of the value of the additional obligations arising from an amendment to the plan, but only in accordance with this chapter and in compliance with the plan provisions required under subparagraph 17 or 18 of the second paragraph of section 14.
- "146.2. All provisions concerning the appropriation of surplus assets during the life of a pension plan must be grouped in an easily identifiable section of the plan.

The same applies to any provision concerning the allocation of surplus assets in the event of termination of the plan.

- "**146.3.** The members and beneficiaries must be informed and consulted before any amendment to the plan under section 146.2.
- "**146.4.** For the purposes of the consultation, the pension committee shall send every member and beneficiary of the plan a written notice which, in addition to containing the information required under subparagraph 1 of the first paragraph of section 26, indicates
- (1) the plan provisions relating to the allocation or appropriation of surplus assets in force on the date of the notice;
 - (2) the text of the plan provisions arising from the amendment; and
 - (3) any other information prescribed by regulation.

The notice must also inform the members and beneficiaries that they may notify the pension committee in writing of their opposition to the proposed amendment to the plan provisions within 60 days after the notice is sent or, as applicable, after the date on which the notice required under the third paragraph is published, whichever is later.

Unless all members and beneficiaries have been personally advised, the pension committee must also publish a notice of the proposed amendment in a daily newspaper circulated in the region in Québec where the greatest number of active members reside. The notice must also specify that persons who have not received a personal notice but believe they must be consulted may declare their status to the pension committee within 60 days after the notice is published and that, if they are able to establish their status, they are entitled to receive a

copy of the notice required under the second paragraph and, if applicable, to notify the committee in writing of their opposition to the proposed amendment.

The notice given under this section is considered to be the notice referred to in section 26.

"146.5. On the expiry of the time for expressing opposition, the pension committee shall count the notices of opposition received.

If 30% or more of the members and beneficiaries are opposed to the proposed amendment, it is deemed rejected and cannot be made.

The pension committee shall immediately inform the employer concerned, as well as each of the plan members and beneficiaries and the person or body who may amend the pension plan, of the results.

"DIVISION II

"PLANS TO WHICH CHAPTER X APPLIES

- "**146.6.** The appropriation, under this division, of the surplus assets of a pension plan to which Chapter X applies, determined without reference to the portion of the assets and that of the liabilities described in section 122.1, is only permitted if, according to the actuarial valuation of the plan, the following conditions are met:
- (1) on a funding basis, the plan's assets are equal to or greater than its liabilities, increased by the value of the stabilization provision target level plus five percentage points; and
- (2) on a solvency basis, the plan's assets are equal to or greater than 105% of its liabilities.
- "146.7. The maximum amount of surplus assets that may be used is equal to the lesser of the following amounts, determined at the date of the actuarial valuation:
- (1) the amount by which the surplus assets determined on a funding basis exceed the minimum set under paragraph 1 of section 146.6; and
- (2) the amount by which the surplus assets determined on a solvency basis exceed the minimum set under paragraph 2 of that section.

In the case of a partial actuarial valuation, the maximum amount of surplus assets is equal to the lesser of the amounts given by the actuary who certifies that a complete actuarial valuation carried out at the date of the valuation would have allowed the determination, in accordance with the first paragraph, of amounts equal to or greater than the amounts given.

"146.8. The amount of surplus assets that may be used over the course of a fiscal year must first be appropriated to the payment of the employer and member current service contributions, up to the lesser of the amount of the employer or member contributions recorded, respectively, under the first and second paragraphs of section 42.2 and the amount of the employer or member current service contributions.

If the amount of surplus assets that may be used is less than the total amount of employer and member contributions recorded under section 42.2, the appropriation under the first paragraph must be proportional to the contributions recorded, respectively, under the first and second paragraphs of that section.

If there is a balance of surplus assets, up to 20% of the balance may, per fiscal year of the plan and in accordance with its provisions, be appropriated to the payment of the value of the additional obligations arising from an amendment to the plan or to the payment of member contributions or be transferred to the employer.

Any amount appropriated to the payment of the employer current service contributions or to the payment of the value of the additional obligations arising from an amendment or transferred to the employer must be deducted from the amounts recorded under section 42.2. The same applies to any amount appropriated to the payment of member current service contributions.

- "**146.9.** The pension plan may provide that the appropriation of surplus assets to the payment of current service contributions may, despite the caps provided for in the first paragraph of section 146.8, apply beyond the amount of the contributions recorded under section 42.2.
- "146.9.1. The appropriation of surplus assets to the payment of employer contributions and, if applicable, member contributions ceases on the date of the end of a fiscal year for which an actuarial valuation or a notice referred to in section 119.1 shows that the conditions set out in section 146.6 are no longer met.

"DIVISION III

"OTHER PLANS

146.9.2. This division concerns the pension plans to which Chapter X does not apply.

It also concerns the portion of the assets and that of the liabilities of a pension plan to which Chapter X applies that are excluded under section 122.1.

"**146.9.3.** The surplus assets of a pension plan may be appropriated to the payment of the value of the additional obligations arising from an amendment to the plan, provided that the amount applied for that purpose is limited to the part of the assets that exceeds the value of the obligations arising

from the plan, established without reference to the additional obligations arising from the amendment, assuming that the plan is terminated.

"**146.9.4.** The portion of the assets of the pension plan that exceeds the value of the obligations arising from the plan, assuming that the plan is terminated, may be appropriated to the payment of employer contributions.

The appropriation of the surplus assets of a pension plan to the payment of employer contributions ceases as soon as the condition set out in the first paragraph is no longer met."

- **28.** Section 146.12 of the Act is amended
- (1) by replacing "sections 138 and 139" in paragraph 1 by "sections 128 and 129";
 - (2) by replacing paragraph 3 by the following paragraph:
- "(3) the sum of the amortization payments determined for the fiscal year and the special improvement payments payable during the fiscal year."
- **29.** Section 146.14 of the Act is repealed.
- **30.** Section 146.15 of the Act is amended by replacing "Sections 60 and 60.1" by "Section 60".
- **31.** Section 146.16 of the Act is replaced by the following section:
- "**146.16.** Despite subparagraph 2 of the first paragraph of section 118 and subparagraph 1 of the first paragraph of section 119, a negotiated contribution plan must be the subject of an actuarial valuation at the date of the end of each fiscal year and the valuation report must be sent to the Régie within six months after the date of the valuation."
- **32.** Section 146.18 of the Act is amended
 - (1) by replacing "128" by "125";
 - (2) by replacing "reserve" by "stabilization provision".
- **33.** Section 146.19 of the Act is replaced by the following sections:
- **"146.18.1.** Section 134, except the exception it provides for, applies to all plan amendments considered for the first time.

Section 139 applies on a solvency basis.

"**146.19.** Despite section 138, the maximum amortization period of any actuarial deficiency is 12 years."

- **34.** Section 146.35 of the Act is amended by replacing "146.3.1" in the third paragraph by "146.4".
- **35.** Section 146.41 of the Act is amended by replacing the second paragraph by the following paragraph:

"The notice referred to in section 200 must not include the information required under paragraph 2 of that section. However, it must mention, if applicable, the cap referred to in the third paragraph."

- **36.** Section 146.45 of the Act is repealed.
- **37.** Section 151.2 of the Act is amended by replacing "to ensure risk management" in subparagraph 6 of the second paragraph by "to quantify and manage risks".
- **38.** Section 166 of the Act is amended
 - (1) by striking out subparagraph 3 of the first paragraph;
- (2) by replacing "in subparagraph 2 or 3" in the second paragraph by "in subparagraph 2".
- **39.** Section 166.1 of the Act is repealed.
- **40.** Section 169 of the Act is amended by replacing ", its characteristics and its financial obligations" by "and its characteristics, financial obligations and funding policy".
- **41.** The Act is amended by inserting the following after section 182:

"DIVISION II.1

"ANNUITY PURCHASING POLICY

"**182.1.** If a pension plan has an annuity purchasing policy that meets the requirements prescribed by regulation, payment of all or part of a pension benefit in accordance with that policy constitutes, on the date of the first payment by the insurer, as stipulated in the agreement entered into for that purpose, final payment of the benefits of the members and beneficiaries covered by that agreement.

The annuity purchasing policy only applies to pensions if, on the date of the agreement with the insurer, they are in payment or an application for payment of benefits has been filed.

"182.2. The members and beneficiaries whose benefits have been paid in accordance with section 182.1 retain, for three years, their status as a member

or beneficiary under the plan for the purposes of the provisions relating to the allocation of surplus assets in the event of termination of the plan. They also retain their status, for the same period, in the event of the employer's bankruptcy or insolvency which, following the employer's withdrawal from the plan or the termination of the plan, results in a reduction of the members' or beneficiaries' benefits.

Whenever the first paragraph must be applied, the notice required under section 207.4 must also state the rules set out in this section."

42. Section 195 of the Act is amended

- (1) by replacing "Division III of Chapter X" in the second paragraph by "Division II of Chapter X";
- (2) by replacing "and the employer's right to appropriate all or part of the surplus assets to the payment of the value of the additional obligations arising from any amendment to the plan or to the payment of employer contributions but, in the latter case, only if the plan from which the assets are to be transferred is a plan to which subparagraph 16.1 or 17 of the second paragraph of section 14 applies or which was amended in that respect under section 146.5" in the fourth paragraph by "and to their appropriation during the life of the plan".
- **43.** The Act is amended by inserting the following section after section 195:
- "**195.0.1.** In the event of division of a pension plan, the amounts recorded under section 42.2 are distributed among the pension plans resulting from the division proportionately to their respective liabilities."

44. Section 196 of the Act is amended

- (1) by inserting the following paragraph before the first paragraph:
- "196. The Régie may only authorize the merger of all or part of the assets and liabilities of several plans if the degree of solvency of the absorbing plan after the merger
- (1) is at least 85% or, in the case of the merger of plans to which the same employer is a party, at least 100%; or
- (2) is not more than five percentage points below the degree of solvency, before the merger, of the absorbing plan or the absorbed plan.";
- (2) by replacing "The Régie shall not authorize the merger of all or part of the assets and liabilities of several plans unless" in the first paragraph by "In addition, the Régie may only authorize the merger if";
- (3) by replacing "ou que si les effets" in the first paragraph in the French text by "ou que les effets";

- (4) by inserting the following sentence after the first sentence of the first paragraph: "Nor shall the Régie authorize the merger unless all the plans include terms which, in relation to the appropriation of surplus assets during the life of the plan, have identical effects.";
- (5) by striking out "only containing the information prescribed by regulation" in the second paragraph;
- (6) by replacing "230.4 and 230.6" in the second paragraph by "146.4 and 146.5":
 - (7) by striking out the fourth paragraph.
- **45.** Section 198 of the Act is amended by adding the following sentence at the end of the second paragraph: "If the amendment is made because the employer no longer has active members in its employ, the amendment becomes effective not later than on the end date of the fiscal year in which the last member ceases to accumulate benefits."
- **46.** The Act is amended by inserting the following section after section 199:
- "199.1. If an employer that is a party to a multi-employer pension plan no longer has active members in its employ, the plan must be amended to allow for the withdrawal of the employer. If the person authorized under the plan to make such an amendment fails to do so within 30 days after the pension committee is informed of the fact that the employer no longer has active members in its employ, the pension committee shall proceed with the amendment.

In the case of an employer all of whose employees covered by the plan are hired on an ad hoc, fixed term basis, the plan need only be amended if 12 months have elapsed since the employer ceased to have active members in its employ."

47. Section 200 of the Act is amended

- (1) by adding "or, if more recent, in the notice sent to the Régie under section 119.1" at the end of paragraph 1;
- (2) by replacing "of the second paragraph of section 230.1 and" in paragraph 2 by "of the plan provisions required under subparagraph 16 of the second paragraph of section 14 and, if applicable,";
 - (3) by replacing paragraphs 3 and 4 by the following paragraphs:
- "(3) that the benefits of non-active members and beneficiaries affected by the withdrawal and whose pension is in payment at the date of withdrawal will be paid by means of a pension paid, as prescribed by regulation, by an insurer selected by the pension committee; and

- "(4) that the benefits of members and beneficiaries affected by the withdrawal, other than those to whom paragraph 3 applies, will be paid by means of a transfer under section 98, which applies with the necessary modifications, or, as applicable, by means of the payment in a lump sum or the transfer into a registered retirement savings plan of the portion of their accrued benefits that is refundable."
- **48.** Section 207.2 of the Act is amended by replacing the third and fourth paragraphs by the following paragraph:

"If applicable, the copy of the report sent to the employer must be accompanied by a notice, a copy of which must be sent to the Régie, indicating that any amount due by the employer according to the report must be paid into the pension fund or to the insurer, as applicable."

- **49.** Section 207.5 of the Act is repealed.
- **50.** Section 207.6 of the Act is amended by replacing the first paragraph by the following paragraph:
- **"207.6.** A pension plan may not be amended after the date of termination, except to allow any increase in pension benefits resulting from the allocation of surplus assets."
- **51.** Section 210.1 of the Act is amended
 - (1) by striking out the first paragraph;
- (2) by adding "de retraite" at the end of the second paragraph in the French text;
 - (3) by striking out the third paragraph.
- **52.** Section 226 of the Act is repealed.
- **53.** Section 230.0.0.1 of the Act is amended by striking out paragraph 2.1.
- **54.** Section 230.0.0.2 of the Act is repealed.
- **55.** Section 230.0.0.3 of the Act is amended by replacing everything that follows "by an insurer" by "or choose a pension paid out of the assets administered by the Régie under section 230.0.0.4".
- **56.** Section 230.0.0.4 of the Act is amended
- (1) by replacing "stipulated under paragraph 2 of section 230.0.0.2 or paragraph 2 of section 230.0.0.3" in the first paragraph by "provided for in section 230.0.0.3";

(2) by inserting the following paragraph after the first paragraph:

"The Régie may administer all or some of the plans together. In such a case, the plans administered together are deemed, for that purpose, to constitute a single plan."

- **57.** Section 230.0.0.9 of the Act is amended
 - (1) by replacing "fifth" in the first sentence of the first paragraph by "tenth";
 - (2) by striking out the second sentence of the first paragraph;
 - (3) by striking out the third paragraph.
- **58.** Section 230.0.0.10 of the Act is amended by replacing "the Government shall pay the required sums to the Régie out of the Consolidated Revenue Fund" by "the Régie may reduce the pensions of the members and beneficiaries".
- **59.** Section 230.0.0.11 of the Act is amended by adding the following paragraph after paragraph 2:
- "(3) prescribe the terms and conditions for reducing the pensions paid by the Régie."
- **60.** Section 230.0.0.12 of the Act is repealed.
- **61.** Section 230.0.1 of the Act is renumbered "230.1".
- **62.** Sections 230.1 to 230.8 of the Act are replaced by the following section:
- **"230.2.** Any surplus assets of a terminated pension plan are first allocated concurrently to the employer and to the members and beneficiaries with benefits under defined benefit provisions, up to the amount of the contributions recorded, respectively, under the first and second paragraphs of section 42.2.

If the amount of surplus assets is less than the total amount of employer and employee contributions recorded under section 42.2, they must be allocated proportionately to the contributions recorded, respectively, under the first and second paragraphs of that section.

Any remaining surplus assets must be allocated in accordance with the conditions and procedure set out in the plan.

The portion allocated to the members and beneficiaries is apportioned among them proportionately to the value of their accrued benefits or according to another method set out in the plan."

63. Section 237 of the Act is amended by inserting "and the variable benefits provided for in section 90.1" after "section 67.2" in the first paragraph.

- **64.** Section 240.2 of the Act is amended by replacing the second paragraph by the following paragraph:
- "Whenever the first paragraph must be applied, the notice required under section 207.4 must also state the rules set out in this section."
- **65.** Section 240.3 of the Act is amended by inserting "or a pension plan that is amended to allow for the withdrawal of an employer" after "pension plan".
- **66.** Section 240.4 of the Act is amended by striking out the second paragraph.
- **67.** Chapter XIV.1 of the Act, comprising sections 243.1 to 243.19, is repealed.
- **68.** Section 244 of the Act is amended, in the first paragraph,
 - (1) by striking out subparagraph 3.0.1;
 - (2) by inserting the following subparagraph after subparagraph 3.1:
- "(3.1.1) determine, for the purposes of section 90.1, the conditions and time limits applicable to the payment of the variable benefits;";
 - (3) by replacing subparagraph 8.0.1 by the following subparagraphs:
- "(8.0.1) determine the information to be contained in the notice required under section 119.1 and the attestations and documents to be included with it;
- "(8.0.2) determine the manner for setting the target level of the stabilization provision required under section 125, and the criteria according to which any scale established is to be applied;
- "(8.0.3) for the purposes of section 142.4, determine the funding requirements to be met by a payment of benefits in accordance with the annuity purchasing policy and the method for calculating and paying the special annuity purchasing payment;
- "(8.0.4) prescribe the requirements regarding the funding policy required under section 142.5;";
 - (4) by inserting the following subparagraph after subparagraph 10:
- "(10.1) prescribe the requirements regarding the annuity purchasing policy referred to in section 182.1;";
- (5) by replacing "of Chapters XIII and XIV.1" in subparagraph 12 by "of Chapter XIII";
 - (6) by striking out subparagraph 12.1.

- **69.** Section 248 of the Act is amended by striking out "or Chapter XIV.1" in subparagraph 5 of the first paragraph.
- **70.** Section 257 of the Act is amended by inserting ", 119.1, 142.5" after "119" in paragraph 1.
- **71.** Section 258 of the Act is amended
 - (1) by replacing "207.5" in paragraph 1 by "207.4";
 - (2) by striking out "230.4, 230.6, 243.8," in paragraph 1.
- **72.** The Act is amended by replacing sections 288.1 to 288.3 by the following sections:
- **"288.1.** The provisions of any defined contribution pension plan that are in force on 31 December 2015 and that pertain to the allocation or appropriation of surplus assets apply, as of 1 January 2016, to the balance of surplus assets referred to in subparagraphs 16 and 17 of the second paragraph of section 14.
- **"288.2.** The letters of credit provided in accordance with section 42.1 before 1 January 2016 are, as of that date, considered to be provided under that section as it applies from that date.
- **"288.3.** If contributions paid before 1 January 2016 were, in accordance with the plan, the subject of special monitoring to allow for the subsequent appropriation or allocation of surplus assets, those contributions must be recorded in accordance with section 42.2 as of that date. The special monitoring must be shown in the actuarial valuation of the plan as at 31 December 2015.
- **"288.4.** The conditions set out in section 20 do not apply to an amendment to a pension plan made before 1 January 2017 to remove the additional pension benefit referred to in section 60.1 or the equivalent benefit or portion of benefit offered by the plan to replace the additional pension benefit."
- **73.** Section 290.1 of the Act is repealed.
- **74.** The Act is amended by inserting the following sections after section 318.1:
- **"318.2.** Any pension plan to which Chapter X applies must be the subject of a complete actuarial valuation on 31 December 2015 in accordance with the provisions in force on 1 January 2016.

For the purposes of the valuation, the amortization payments required, on a solvency basis and a funding basis, for an unfunded actuarial liability determined in a prior actuarial valuation, are eliminated.

"318.3. Despite paragraphs 1 and 2 of section 138, the amortization period of any technical actuarial deficiency or any stabilization actuarial deficiency that begins on the date of an actuarial valuation prior to 31 December 2016 expires on the date of the end of the fiscal year of a pension plan that ends no later than 15 years after the date of the valuation. The maximum amortization period of such an actuarial deficiency beginning after 30 December 2016 is reduced by one year for every full year of deviation between 31 December 2015 and the date on which the amortization period of the deficiency begins.

The amortization period of any technical actuarial deficiency or any stabilization actuarial deficiency that begins after 30 December 2020 is determined in accordance with section 138.

"318.4. If the employer contributions that are determined in the actuarial valuation required under section 318.2 or a subsequent actuarial valuation and that are payable for every fiscal year or part of a fiscal year after the valuation date are greater than those that would have been payable from 1 January 2016 to 31 December 2016 under the provisions in force on 31 December 2015, the difference is only payable at a rate of one third per 12-month period as of 1 January 2017.

For the purposes of the first paragraph, the employer current service contributions corresponding to the value of the obligations arising from the pension plan in relation to credited service completed during the fiscal year are to be excluded.

To determine the contributions that would have been payable, any instruction given in relation to the period including the pension plan's fiscal year in progress on 31 December 2015 under the Regulation providing new relief measures for the funding of solvency deficiencies of pension plans in the private sector (chapter R-15.1, r. 4.1) and applied on that date must be taken into account.

If applicable, section 42.1 applies taking into account only the portion of the stabilization amortization payment payable under the first paragraph.

This section ceases to apply on 31 December 2018.

"318.5. A pension plan that is exempted, under a regulation made under section 2, from the application of the funding rules set out in this Act is subject to the provisions of this Act that are in force on 1 January 2016 but only to the extent prescribed by the regulation applicable to the plan.

Section 142.5 applies, however, to a plan referred to in the first paragraph.

If such a regulation ceases to apply to a pension plan, sections 318.2 to 318.4 apply to such a plan, and in applying those sections, the date of 1 January 2016 is replaced by the date following the date on which the regulation ceases to apply and the other dates mentioned in those sections are replaced accordingly.

The provisions of Chapter X, as they read on 31 December 2015, continue to apply to any pension plan administered by the Régie under subdivision 4.0.1 of Division II of Chapter XIII.

- "**318.6.** The fact that the Regulation respecting supplemental pension plans affected by the arrangement regarding AbitibiBowater Inc. under the Companies' Creditors Arrangement Act (chapter R-15.1, r. 6.1) ceases to apply before 31 December 2020 does not cause Division IV of the Regulation to cease to apply.
- **"318.7.** The provisions of subdivision 4.0.1 of Division II of Chapter XIII that are in force on 31 December 2015 continue to apply to pensions being paid by the Régie under those provisions at 31 December 2015.

In addition, a pension plan to which Chapter X applies and that meets all the conditions set out in section 230.0.0.1, as it read on 31 December 2015, is subject to the provisions mentioned in the first paragraph, unless it was liquidated before 1 January 2016.

- **"318.8.** If the termination report regarding a pension plan referred to in the provisions of subdivision 4.0.1 of Division II of Chapter XIII that come in force on 1 January 2016 was sent to the Régie before that date, the rights of the members and beneficiaries are established based on that report."
- **75.** The Act is amended by inserting the following section after section 319.10:
- "**319.11.** For the sole purpose of allocating the assets of a pension plan under the Agreement Respecting Multi-Jurisdictional Pension Plans, which came into force on 1 July 2011, the members' benefits accrued before 1 January 2016 are included in the benefits funded on a solvency basis."

TRANSITIONAL AND FINAL PROVISIONS

- **76.** The regulations made for the purposes of the provisions enacted by this Act may have retroactive effect from a date not prior to 1 January 2016.
- 77. Unless the parties agree otherwise, an agreement entered into before 1 January 2016 regarding the sharing of the current service contribution is considered to apply as well to the current service stabilization contribution as of 1 January 2016 or a later date stipulated in the agreement.
- **78.** This Act comes into force on 1 January 2016.



SONSOLIDATED TOTAL FOR ALL PLANS ENBRIDGE GAS DISTRIBUTION INC. **ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016** ASC 715 (US GAAP)

February 2017



ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

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_	2. Basis of Valuation	3. Notices and Professional Qualifications

Appendix A: Disclosure Information

Appendix B: Estimated Net Periodic Benefit Cost Information

Appendix C: Plan Assets

Appendix D: Actuarial Assumptions

Appendix E: Actuarial Methods

Appendix F: EGD RPP Disclosure Information - By Employer

Appendix G: Employer Certification

Report Highlights

Mercer has prepared this report for Enbridge Gas Distribution Inc. and it's subsidiary companies ("EGD") to (i) present actuarial estimates of iabilities as at December 31, 2016, for the following plans: Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the statements prepared in accordance with accounting principles generally accepted in the United States of America ("US GAAP"), and to (ii) "EGD RPP"), Supplemental Executive Retirement Plan of Enbridge Gas Distribution and Affiliates (the "SERP"), Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc. (the "SSERP"), to incorporate as EGD deems appropriate, in its financial provide an actuarial estimate of the net periodic benefit cost for the fiscal year ending December 31, 2017.

The EGD RPP has a defined contribution component as well as a defined benefit component. The results presented in this report consider annual contribution requirements. Pension benefits payable from the defined benefit component are based on length of service and final both components of the EGD RPP. The EGD RPP is funded by contributions from EGD unless it elects to use a funding excess to meet average earnings and are partially indexed for inflation after retirement.

service and final average earnings and are partially indexed for inflation after retirement. There are no longer any active members in the The SERP and the SSERP are closed plans, funded by contributions from EGD as necessary. Pension benefits are based on length of

All figures in this report are expressed in Canadian dollars unless otherwise stated.

Please see Section 3 of this report for further explanation as to the purposes and limitations of this report.

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Summary of Results

Below are highlights of the results as at December 31, 2016, compared to the corresponding figures as at December 31, 2015.

	Fiscal year ending December 31, 2016	Fiscal year ending December 31, 2015
Net periodic benefit cost (DB)	\$19,345,100	\$31,559,900
Net periodic benefit cost (DC)	\$899,700	\$1,011,800
Benefit obligation	\$1,086,296,300	\$1,015,385,200
Fair value of plan assets	\$988,261,800	\$962,244,600
Funded status	(\$98,034,500)	(\$53,140,600)
Composite discount rate at year-end for all plans	3.91%	4.20%
Composite expected rate of return on assets at year-end for all plans	6.42%	6.41%

As instructed by EGD, the reduction in workforce that occurred in the last quarter of 2016 did not trigger a curtailment. Therefore, the net periodic benefit cost for the fiscal year ending December 31, 2016, includes no charges/credits due to special events.

The estimated net periodic benefit cost for the fiscal year ending December 31, 2017, is \$19,824,300 (DB) and \$851,700 (DC)

Please note that the actual net periodic benefit cost for the fiscal year ending December 31, 2017, may be substantially different from the estimate and may be revised if assets and/or liabilities are remeasured during the year due to a significant event and/or cash flows are updated. We have not been notified by EGD nor are we aware of any events subsequent to December 31, 2016, which in our opinion would have a material impact on the results of the valuation

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016 **Changes in Plan Provisions**There were no changes in plan provisions since the prior valuation.

Changes in Actuarial Assumptions

The actuarial assumptions changed since the last actuarial valuation as at December 31, 2015. Details are shown in Appendix D.

The approach used for setting the assumptions is similar to the prior year.

Changes in Actuarial Methods

There have been no changes to the actuarial methods since the prior valuation.

Changes in Data

We have incorporated new membership data in the valuation of the benefit obligations as at December 31, 2016 as described in Section 2. In addition, we have updated the value of plans' assets to reflect changes to December 31, 2016.

To our knowledge there have been no other changes since the prior valuation that will affect the valuation results.

Details of the disclosure information are shown in Appendix A. The estimated net periodic benefit cost information for the fiscal year ending December 31, 2017 is shown in Appendix B. Details of plan assets are shown in Appendix C.

Please refer to the remainder of the report for more information about these summary numbers.

Basis of Valuation

Plan Data

audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and To prepare this report Mercer has used and relied on financial data submitted as at the measurement date by CIBC Mellon without further we have no reason to doubt its substantial accuracy.

2015 as supplied by EGD. The membership data is summarized in Appendix E of the following reports effective December 31, 2015 (the Mercer has also used and relied on participant data as described in the funding valuations as at December 31, 2014 and December 31, "Funding Reports"):

- The Report on the Actuarial Valuation for Funding Purposes as at December 31, 2015 of the Pension Plan for Employees of Enbridge Gas Distribution Inc. and Affiliates (the "EGD RPP Funding Report"); and
- EGD RPP, SERP and SSERP Preliminary Valuation Results as of December 31, 2015 Presentation dated April 8, 2016

contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum terms of the plans or otherwise entitled to benefits that is sufficiently comprehensive and accurate for the purposes of this report. If the data payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests supplied are not sufficiently comprehensive and accurate for the purposes of this report, the valuation results may differ significantly from EGD is responsible for ensuring that such participant data provides an accurate description of all persons who are participants under the reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, the results that would be obtained with such data; this may require a later revision of this report. We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership were satisfactory.

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Actuarial Assumptions

plan's actual experience will differ from those assumptions; these differences may be significant or material because these results are very To prepare the valuation report, assumptions are used in a forward looking financial and demographic model to present a single scenario from a wide range of possibilities; the results based on that single scenario are included in the valuation. The future is uncertain and the sensitive to the assumptions made and, in some cases, to the interaction between the assumptions. Different assumptions or scenarios within the range of possibilities may also be reasonable and results based on those assumptions would uniquely 'correct' and many alternative projections of the future could also be regarded as reasonable. Two different actuaries could, quite reasonably, arrive at different results based on the same data and different views of the future. A 'sensitivity analysis' shows the degree to which results would be different if you substitute alternative assumptions within the range of possibilities for those utilized in this report. be different. As a result of the uncertainty inherent in a forward looking projection over a very long period of time, no one projection is

A sensitivity analysis was performed with respect to the discount rate (-0.5% in discount rate), rate of salary increase (-0.5% in salary increase), and expected return on assets (-0.5% in expected return). Details of this analysis can be found in the disclosure results in Appendix A.

changes in expectations about the future and other factors. A change in assumptions is not an indication that prior assumptions were Assumptions may also be changed from one valuation to the next because of changes in mandated requirements, plan experience, unreasonable when made.

Actuarial Methods

A valuation report is only a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict the plan's future Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid financial condition or its ability to pay benefits in the future and does not provide any guarantee of future financial soundness of the plan. benefits, the period of time over which benefits are paid, plan expenses and the amount earned on any assets invested to pay benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

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ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

used, in our judgment, would not have significantly affected our results. Use of such simplifying techniques does not, in our judgment, affect Because modelling all aspects of a situation is not possible or practical, we may use summary information, estimates, or simplifications of estimates to facilitate the modelling of future events in an efficient and cost-effective manner. We may also exclude factors or data that, if the reasonableness of valuation results for the plan.

time. If the costs recognized over a period of years are lower or higher than necessary, for whatever reason, normal and expected practice Valuations do not affect the ultimate cost of the plan, only the timing of when benefit costs are recognized. Cost recognition occurs over is to adjust future expense levels with a view to recognizing the entire cost of the plan over time.

As instructed, Mercer has prepared the accounting disclosures in this report based on EGD's accounting policies.

A summary of the actuarial methods, accounting policies and valuation procedures is provided in Appendix E.

Plan Provisions

Mercer has used and relied on the plan documents, including amendments, and interpretations of plan provisions, supplied by EGD as summarized in the following reports:

- Appendix F of the EGD RPP Funding Report for the EGD RPP;
- Appendix F of The Report on the Actuarial Valuation for Funding Purposes as at December 31, 2013 of the Supplementary Executive Retirement Plan of Enbridge Gas Distribution Inc. and Affiliates; and
- Appendix E of The Report on the Actuarial Valuation for Funding Purposes as at December 31, 2013 of the Supplementary Senior Executive Retirement Plan of Enbridge Gas Distribution Inc.

accurate and complete, the valuation results may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be subject to different interpretations, each of which could be reasonable, and the results EGD is solely responsible for the validity, accuracy and comprehensiveness of this information. If any plan provisions supplied are not under each of the different interpretations could vary.



Notices and Professional Qualifications

Mercer has prepared this report exclusively for EGD; subject to this limitation, EGD may direct that this report be provided to its auditors in connection with the audit of its financial statements. Mercer is not responsible for use of this report by any other party. The only purposes of this report are to present actuarial estimates of liabilities as at December 31, 2016, for the following plans: EGD RPP, SERP and SSERP, to be incorporated, as EGD deems appropriate, in its financial statements prepared in accordance with US GAAP standards, and to provide an actuarial estimate of the net periodic benefit cost for the fiscal year ending December 31, 2017.

This report may not be used for any other purpose. Mercer is not responsible for the consequences of any unauthorized use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. The rationale for significant assumptions used as at December 31, 2016 and for which we assisted EGD is summarized in Appendix D.

This report was prepared in accordance with generally accepted actuarial principles and procedures. The actuarial assumptions were selected by EGD. Based on the information provided to us, we believe that the actuarial assumptions are reasonable for purposes described in this report. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues and societal factors, including financial scenarios that assume future sustained investment losses.

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

EGD is ultimately responsible for selecting the plan's accounting policies, methods, and assumptions. This information is referenced or described in Section 2 of this report. EGD is solely responsible for communicating to Mercer any changes required to those policies, methods and assumptions. EGD is solely responsible for selecting the plan's investment policies, asset allocations and individual investments. The Mercer actuaries who prepared this report have not provided any investment advice to EGD. This report is based on our understanding of applicable law and regulations as at the valuation date. Mercer is not an accountant or auditor standards provided in this report are for reference purposes only. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this and is not responsible for the interpretation of, or compliance with, accounting standards; citations to, and descriptions of accounting

EGD should notify Mercer promptly after receipt of this valuation report if EGD disagrees with anything contained herein or is aware of any information that would affect the results of this report that has not been communicated to Mercer or incorporated therein. The valuation report will be deemed final and acceptable to EGD unless EGD promptly provides such notice to Mercer

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Professional Qualifications

report. I am not aware of any direct or material indirect financial interest or relationship, including investments or other services that could appropriate. I meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this am available to answer any questions on the material contained in this report, or to provide explanations or further details as may be create a conflict of interest, that would impair the objectivity of this work.



February 7, 2017

Date

Benedict O. Ukonga FSA, FCIA Mercer 120 Bremner Boulevard, Suite 800 Toronto, ON M5J 0A8 +1 416 868 2000

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

APPENDIX A

Disclosure Information

		200		Ĺ	9		9	2	
	Plan Name:	EGU RPP	777	SERF	F	SOEKY	Ť.	All Plans	ans
	Fiscal year ending on	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
۵	Change in benefit oblication								
	1 Donofit obligation of the givening of the r	006 004 600	1 047 630 900	15 201 600	16.078.800	000000	000 100 1	1 015 205 200	4 020 020 600
•	Service cost	30,947,700	34,110,000		000,070,01	4,002,000	- , 554, 200	30,947,700	34,110,000
	3. Interest cost	34,101,400	39,882,100	476,900	623,400	110,800	165,600	34,689,100	40,671,100
	4. Employee contributions								
	5. Plan amendments								
-	6. Plan curtailments							•	
	7. Plan settlements								
	8. Special termination benefits								
	9. Benefits paid from the plan	(44,758,400)	(41,585,000)	(1,003,500)	(009'026)	(399,300)	(396,500)	(46,161,200)	(42,952,100)
	10. Medicare subsidies received	•							
	11. Expenses paid	•			•	•	•	•	
	12. Taxes paid								
	13. Premiums paid								
	14. Net transfer in/(out)								
	15. Plan combinations								
	16. Actuarial loss (gain)	50,101,000	(54,034,300)	000,796	(427,800)	367,500	(21,300)	51,435,500	(54,483,400)
	17. Exchange rate changes	•	•				•		,
	18. Benefit obligation at end of year	1,066,393,300	996,001,600	15,742,000	15,301,600	4,161,000	4,082,000	1,086,296,300	1,015,385,200
α	Change in plan assets								
	1. Fair value of plan assets at beginning of year	937,095,800	930,244,200	17,022,900	17.284.300	8,125,900	8.194.400	962,244,600	955,722,900
	2. Actual return on plan assets	71,113,400	48,436,600	006'299	554,100	386,200	328,000	72,167,500	49,318,700
•	3. Employer contributions to plan			10,900	155,100		•	10,900	155,100
	4. Employee contributions								
-	5. Plan settlements	•			•	•		•	
	6. Benefits paid from the plan	(44,758,400)	(41,585,000)	(1,003,500)	(009'026)	(399,300)	(396,500)	(46,161,200)	(42,952,100)
	7. Medicare subsidies received	•				•		•	
-	8. Expenses paid	•	•		•	•	•	•	
	9. Taxes paid				•		i		
	10. Premiums paid	•	•	•			i	•	•
	11. Acquisitions / divestitures	•	•	•			i	•	•
	12. Plan combinations	•				•		•	
	13. Adjustments			•			•	•	
	14. Exchange rate changes		•			•	-		
	15. Fair value of plan assets at end of year	963,450,800	937,095,800	16,698,200	17,022,900	8,112,800	8,125,900	988,261,800	962,244,600

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

	Plan Name:	EGD RPP	дЫ	SERP	٩	SSERP	۲P	All Plans	ans
(12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
ز	, Kec	000 450 000	0034 006 800	000	44 000 000	000	0407	000	069 244
		963,430,600	937,093,600	16,696,200	17,022,900	0,112,600	0,123,900	1 086 286 300	362,244,600
		000,000,000,	000,100,066	3,7 44,000	000,100,01	1,000	4,002,000	000,062,000,1	002,000,010,1
	 Funded status (plan assets less benefit obligations) Contributions and distributions made by company from measurement date to fiscal year end 	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(98,034,500)	(53,140,600)
	recognized in statement of financial position	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(98,034,500)	(53,140,600)
Ö	Amounts recognized on the consolidated balance sheet position consists of	_							
	1. Noncurrent assets			956,200	1,721,300	3,951,800	4,043,900	4,908,000	5,765,200
	2. Current liabilities								
	3. Noncurrent liabilities	(102,942,500)	(58,905,800)	1			•	(102,942,500)	(58,905,800)
	4. Net as set (obligation) recognized in statement of financial position	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(98,034,500)	(53,140,600)
Ш	Reconciliation of amounts recognized in statement of financial position								
	 Initial net asset(obligation) 						•		
	2. Prior service credit (cost)	•	•	•	•	•	i	•	
	3. Netgain (loss)	(306,084,400)	(281,512,800)	(3,773,200)	(3,020,200)	102,800	337,900	(309,754,800)	(284,195,100)
	4. Accumulated other comprehensive income (loss)	(306,084,400)	(281,512,800)	(3,773,200)	(3,020,200)	102,800	337,900	(309,754,800)	(284,195,100)
	5. Accumulated contributions in excess of net periodic benefit cost	203,141,900	222,607,000	4,729,400	4,741,500	3,849,000	3,706,000	211,720,300	231,054,500
	6. Net as set (obligation) recognized in statement of financial position	(102,942,500)	(58,905,800)	956,200	1,721,300	3,951,800	4,043,900	(98,034,500)	(53,140,600)
ш	Components of net periodic benefit cost								
	1. Service cost	30,947,700	34,110,000					30,947,700	34,110,000
	2. Interest cost	34,101,400	39,882,100	476,900	623,400	110,800	165,600	34,689,100	40,671,100
	3. Expected return on plan assets	(59,502,300)	(61,402,500)	(531,500)	(542,200)	(253,800)	(256,000)	(60,287,600)	(62,200,700)
	4. Amortization of initial net obligation (asset)		•			•			
	Amortization of prior service cost		•				•	•	
	6. Amortization of net (gain) loss	13,918,300	18,556,100	77,600	423,400			13,995,900	18,979,500
	7. Curtailment (gain) / loss recognized	•	•			•	•	•	•
	8. Settlement (gain) / loss recognized	•	•	•	•	•	i	•	
	Special termination benefit recognized		•	•		•	-	•	
	10. Net periodic benefit cost	19,465,100	31,145,700	23,000	504,600	(143,000)	(90,400)	19,345,100	31,559,900

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Plan Name:	EGD RPP	ЬР	SERP	0	SSERP	٦۶	All Plans	ans
Fiscal year ending on	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
G. Changes recognized in other comprehensive income								
Cnanges in plan assets and benefit obligations								
New pilot service cost Net loce (rein) pricing during the year*	38 480 000	- (41 068 400)	009088	(439 700)	238 100		30 555 600	(41 601 400)
	006,604,00	(00+,000,1+)	000,000	(1007,854)	233,100	(000,00)	000,000,60	(40,400)
 Effect of exchange rates on amounts included in AOCI 								
2								
4. Amortization, settlement or curtailment recognition of net transition	•							•
asset(obligation)								
Amortization or curtailment recognition of prior service credit (cost)								•
6. Amortization or settlement recognition of net gain (loss)	(13,918,300)	(18,556,100)	(77,600)	(423,400)			(13,995,900)	(18,979,500)
	24.571.600	(59.624.500)	753.000	(863.100)	235.100	(93,300)	25.559.700	(60,580,900)
8. Total recognized in net periodic benefit and other comprehensive loss								
= (income)	44,036,700	(28,478,800)	776,000	(358,500)	92,100	(183,700)	44,904,800	(29,021,000)
	5							
Estimated amounts that will be amortized from accumulated								
other comprehensive income over the next fiscal year								
9. Initial net asset (obligation)								
10. Prior service credit (cost)								
11. Net gain (loss)	(15,086,600)		(129,300)				(15,215,900)	
	(15,086,600)		(129,300)		,		(15,215,900)	
Weighted a manage and amondians to determine houngft a hillsonian								
1. Discountrate	3.92%	4.20%	3.69%	4.20%	3.31%	4.20%	3.91%	4.20%
	3 46%	3 430/	3 250%	3 25%	oldenilane told	oldenilare told	3 460	3 430
3. Measurement date	31-Dec-2016	31-Dec-2015	31-Dec-2016	31-Dec-2015	31-Dec-2016	31-Dec-2015	31-Dec-2016	31-Dec-2015
Assumptions to determine net cost	7000	7000	7 2000	7000	7 200%	7000	7000	7000
a Ellective discountriate for Deficit Objigations	0,02.4	700%	707:4	2,00%	20.04.0	700%	4.50%	7007
D. Effective rate for interest on benefit obligations Effective rate for service cost	3.50%	4.00%	3.22%	4.00%	2.05%	4.00%	3.49%	4.00%
C. Effective rate for interest to a consist one	4 0 2%	4 00%	Not applicable	4 00%	aldezilane told	4 00%	4 02%	4 00%
	4.55%	4.00%	3 20%	3 20%	3 20%	3 20%	4.02% A 11%	99.4
Rate of compensation increase	3.43%	3.65%	3.25%	3.90%	Notapplicable	Notapplicable	3.43%	3.65%
 Additional year-end information 								
Required information for all defined benefit plans								
1. Accumulated benefit obligation	978,238,800	914,766,400	15,640,900	15,019,100	4,161,000	4,082,000	998,040,700	933,867,500
Sensitivity to key as sumptions for pension plans								
2. Sensitivity to key assumptions								
a. Half a percent decrease in expected return on assets								
i. Effect on pension expense	4,577,100		83,100		39,700		4,699,900	
ii. Effect on year-end benefit obligation								
b. Half a percent decreas e in dis count rate								
i. Effect on pension expense	6,514,200		1,000		(15,300)		6,499,900	
ii. Effect on year-end benefit obligation	85,689,100		894,700		158,900		86,742,700	
c. Half a percent decrease in rate of salary increase								
i. Effect on pension expense	(2,903,200)		(800)				(2,904,000)	
ii. Effect on year-end benefit obligation	(14,702,600)		(8,700)				(14,711,300)	

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Plan Name:	EGD RPP	\PP	SERP		SSERP	Ь	AIP	All Plans
	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
K. Additional year-end information for plans with accumulated benefit								
1. Projected benefit obligation	1.066.393.300						1.066.393,300	
	978,238,800						978,238,800	
3. Fair value of plan assets	963,450,800	•			•	•	963,450,800	•
L. Additional year-end information for plans with projected benefit								
obligations in excess of plan assets 1. Projected benefit obligation	1,066,393,300	996,001,600	٠				1,066,393,300	996,001,600
	963,450,800	937,095,800			•		963,450,800	937,095,800
M. Cash flows								
 Projected company contributions for fiscal year ending: 								
31-Dec-2017:	34,407,100		10,900				34,418,000	
31-Dec-2018:	35,179,900		10,900				35,190,800	
31-De6-2019 :	35,979,400		008,01				35,990,300	
31-Dec-2020 ;	25,596,400						25,596,400	
31 Doc 2021 :	27.384.600						27 384 600	
31-Dec-2022 :	28.323.800						28.323.800	
31-Dec-2024	29.295.500						29,295,500	
31-Dec-2025	30,300,200						30,300,200	
31-Dec-2026:	31,339,600						31,339,600	
2. Expected benefit payments for FYE								
	47 646 200		1 024 000		391 300		49.061.500	
31-Dec-2018:	48,873,200		1,042,100		386,000		50,301,300	
31-Dec-2019:	50,161,300		1,049,200		379,500		51,590,000	
31-Dec-2020:	51,544,800		1,049,700		371,700		52,966,200	
31-Dec-2021:	53,066,000		1,045,800		362,200		54,474,000	
Next five years	288,254,900		5,091,500		1,607,500		294,953,900	
N. Accumulated contributions in excess of net periodic benefit cost								
1. Amountas of beginning of year	222,607,000	253,752,700	4,741,500	5,091,000	3,706,000	3,615,600	231,054,500	262,459,300
2. Netperiodic pension (cost) income for fiscal year	(19,465,100)	(31,145,700)	(23,000)	(504,600)	143,000	90,400	(19,345,100)	(31,559,900)
3. Employer contributions made in fiscal year (excludes contributions			10 900	155 100		٠	10 900	155 100
made between measurement year end and fis cal year end)								
	,							
5. FAS 88 (expense) income		٠			٠			
							•	
7. Plan combinations								
8. Adjustment to match local books		•			•		•	
9. Exchange rate adjustment							•	
	203,141,900	222,607,000	4,729,400	4,741,500	3,849,000	3,706,000	211,720,300	231,054,500
11. Contributions and direct benefit payments made between	•	•	,				•	
12 Amount as of end of waar	203.141.900	222,607,000	4.729.400	4.741.500	3.849.000	3.706.000	211.720.300	231.054.500

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Plan Name:	EGD	EGD RPP	SE	SERP	SSERP	RP	AIIP	All Plans
Fiscal year ending on	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
O. Reconciliation of transition obligation (asset)								
1. Amountas disclosed as of prior year end	•	•	•			•	•	•
Amounts recognized as a component of net periodic b enefit cost								
2. Amortization						•		•
3. Effect of curtailment								
4. Effect of settlement	•	•	•		•	•	•	•
5. Total amount recognized as a component of net periodic benefit cost	ost -		•					
Other changes (adjustment to accumulated comprehensive income, retained ea	tained earnings)							
6. Plan combinations					•	•		
7. Difference between prior year end and beginning of current year					•	•		
8. Total amount recognized as other change in accumulated other		•	•		•	,	•	
comprehensive income								
9. Exchange rate adjustment		•	1	•	•		•	•
10. Amount at end of year	•	•	•				•	
P. Reconciliation of prior service cost (credit)								
 Amount as disclosed as of prior year end 	•				•	•	•	
Amounts recognized as a component of net periodic b enefit cost								
2. Amortization				•	•	•	•	•
3. Effect of curtailment								
4. Total amount recognized as a component of net periodic benefit cost	ost -							
Changes in plan assets and benefit ob ligations recognized in other comprehensive income	mprehensive income							
5. Plan amendments	•	•						
Other changes (adjustment to accumulated comprehensive income, retained ea	tained earnings)							
6. Plan combinations								
7. Difference between prior year end and beginning of current year	•	•	i		•	•	•	•
8. Total amount recognized as other change in accumulated other					1			
comprehensive income								
Exchange rate adjustment								
10. Amount at end of year	•	•	•	•		•	•	

ASC 715 (US GAAP)
ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

	Plan Name:	EGD RPP	PP	SERP	۵.	SSERP	Д.	All Plans	ans
(12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015	12/31/2016	12/31/2015
o i	Reconciliation of net (gain) loss	281 512 800	341 137 300	3 020 200	3 883 300	(337 900)	(244 600)	284 195 100	344 776 000
	Amounts recognized as a component of net periodic benefit cost	000,4		001,010,0		(000,100)	(000,112)	,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,,	
	2. Amortization	(13,918,300)	(18,556,100)	(77,600)	(423,400)			(13,995,900)	(18,979,500)
	3. Effect of settlement	•	•		•			•	
	4. Total amount recognized as a component of net periodic benefit cost	(13,918,300)	(18,556,100)	(77,600)	(423,400)			(13,995,900)	(18,979,500)
	ja,	nsive income	2000	0000	(000	11	300	, , , , , , , , , , , , , , , , , , ,	, , , , , , , , , , , , , , , , , , ,
		50,101,000	(54,034,300)	967,000	(427,800)	367,500	(21,300)	51,435,500	(54,483,400)
	b. Asset experience	(001,116,111)	12,965,900	(136,400)	(008,11)	(132,400)	(72,000)	(11,879,900)	12,882,000
	Transmission of the second of	38,489,900	(41,068,400)	830,600	(439,700)	235,100	(93,300)	39,555,600	(41,601,400)
	adjustment to accumulated comprehensive income, retained	eamings)							
	10. Plan combinations								
					i			•	•
	12. Difference between prior year end and beginning of current year						•		•
	13. Difference between calculated year-end gain/loss and amount using	٠					٠		•
	events that occurred during the year								
	 Total amount recognized as other change in accumulated other comprehensive income 	•	٠	1	1	ı	٠	•	•
	15. Exchange rate adjustment			•	,	•	•	•	,
	16. Amountatend of year	306,084,400	281,512,800	3,773,200	3,020,200	(102,800)	(337,900)	309,754,800	284,195,100
œ	Composition of asset balance for supplemental plans 1. Market value of RCA invested assets as per CIBC Mellon statement 2. Estimated value of Refundable Tax Account (RTA)			9,105,600 7,592,600	9,275,000	5,331,900	5,422,200 2,703,700	14,437,500	14,697,200
				16,698,200	17,022,900	8,112,800	8,125,900	24,811,000	25,148,800
ø,	DC current service cost	899,700	1,011,800					899,700	1,011,800
	Projected DC current service cost for fiscal year ending:								
	31-Dec-2017:	851,700						851,700	
	31-Dec-2018:	881,300						881,300	
	31-Dec-2019:	911,900						911,900	
	31-Dec-2020:	943,500						943,500	
	31-Dec-2021:	976,300						976,300	
	31-Dec-2022:	1,010,200						1,010,200	
	31-Dec-2023:	1,045,200						1,045,200	
	31-Dec-2024:	1,081,400						1,081,400	
	31-Dec-2025 :	1,119,000						1,119,000	
	31-Dec-2026 :	0,00,000						200,101,1	

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

APPENDIX B

Estimated Net Periodic Benefit Cost Information

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Fiscal year ending on Components of projected net periodic benefit cost 1. DB service cost 2. Interest cost 3. Expected return on plan assets 4. Amortization of initial net obligation (asset) 5. Amortization of prior service cost 6. Amortization of prior service cost 7. Curtailment (gain) / loss recognized 8. Settlement (gain) / loss recognized 9. Special termination benefit recognized 10. Net periodic benefit cost 11. Defined contribution service cost	12/31/2017 32,284,000 34,717,500 (62,194,100) - 15,086,600 - 15,086,600	SERP 12/31/2017 464,500 (518,100) (518,100) 129,300 129,300	1231/2017 107,900 (253,300) 	All Plans 12/31/2017 32,284,000 35,289,900 (62,965,500) (15,215,900
tional items For Net Periodic Benefit Cost Calculations Fair value of assets Market-related value of assets a. Expected benefits paid from plan assets	963,450,800 963,450,800 47,646,200	16,698,200 16,698,200 1,024,000	8,112,800 8,112,800 391,300	988,261,800 988,261,800 49,061,500
 Weighted for timing Expected employer contributions to plan assets Weighted for timing Average future years of service	23,823,100 34,407,100 17,203,600	512,000 10,900 5,500 16.27	195,700	24,530,800 34,418,000 17,209,100 N/A
Benefit Obligations and Assets Funded Status Projected benefit obligation (PBO) / Accum ulated postretirement 1. benefit obligation (APBO) 2. Fair value of plan as sets 3. Funded status (1.+ 2.)	(1,066,393,300) 963,450,800 (102,942,500)	(15,742,000) 16,698,200 956,200	(4,161,000) 8,112,800 3,951,800	(1,086,296,300) 988,261,800 (98,034,500)
Weighted-average assumptions to determine net cost 1. Effective discount rate for defined benefit obligations 2. Effective rate for net interest cost 3. Effective discount rate for service cost 4. Effective rate for interest on service cost 5. Expected return on assets 6. Salaryscale	3.92% 3.33% 4.14% 3.85% 6.50% 3.46%	3.69% 3.05% Not applicable Not applicable 3.20% 3.25%	3.31% 2.72% Not applicable Not applicable 3.20% Not applicable	3.91% 3.32% 4.14% 3.85% 6.42% 3.46%

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APPENDIX C

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Plan Assets

Plan assets have been taken at their fair value as provided by CIBC Mellon via their online tool Workbench on January 12, 2017.

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

APPENDIX D

Actuarial Assumptions

The assumptions as at the reporting date are use benefit cost for the following year. We have used assumptions used at December 31, 2016, and D	The assumptions as at the reporting date are used to determine the present value of the benefit obligation at that date and the net periodic benefit cost for the following year. We have used actuarial assumptions selected by EGD. The principal financial and demographic assumptions used at December 31, 2016, and December 31, 2015, are shown in the table below.
Discount rate used for determine benefit obligation determination	 EGD RPP: 3.92% per year for year-end disclosure December 31, 2016 4.20% per year for year-end disclosure December 31, 2015 3.69% per year for year-end disclosure December 31, 2016 4.20% per year for year-end disclosure December 31, 2015 3.31% per year for year-end disclosure December 31, 2016 4.20% per year for year-end disclosure December 31, 2016 4.20% per year for year-end disclosure December 31, 2015
Discount rate used for determine current service cost determination (EGD RPP only)	 4.14% per year for 2017 expense determination 4.30% per year for 2016 expense determination 4.00% per year for 2015 expense determination

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Effective discount rate for interest cost on benefit	EGD RPP:
obligation	• 3.33% per year for 2017 expense determination
	• 3.50% per year for 2016 expense determination
	 4.00% per year for 2015 expense determination
	SERP:
	 3.05% per year for 2017 expense determination
	 3.22% per year for 2016 expense determination
	 4.00% per year for 2015 expense determination
	SERP:
	 2.72% per year for 2017 expense determination
	 2.85% per year for 2016 expense determination
	 4.00% per year for 2015 expense determination
Effective discount rate for interest on current	 3.85% per year for 2017 expense determination
service cost (EGD RPP only)	 4.02% per year for 2016 expense determination
	 4.00% per year for 2015 expense determination
Expected long-term rate of return on assets	EGD RPP:
	 6.50% per year for 2016 and 2017 expense determination
	 6.75% per year for 2015 expense determination
	SERP and SSERP:
	 3.20% per year for the 2017, 2016 and 2015 expense determination
Inflation	• 2.00% per year
Increases in pensionable earnings	 2.50% plus age graded merit and promotion scale (see tables of sample rates)
Bonus	 135% of target bonus
Target bonus	 Senior manager: Actual target bonus
	 Non-senior manager: 12% non-union / 5% union
Increases in the YMPE	• \$54,900 in 2016 and increasing by 2.50% per year for year-end disclosure December 31, 2016
	and 2017 expense determination
	• \$53,600 in 2015 and increasing by 2.50% per year for year-end disclosure December 31, 2015
	and 2016 expense determination

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Increases in maximum pension permitted under	•	\$2,890.00 in 2016 and increasing by 2.50% per year for year-end disclosure December 31, 2016
the <i>Income Tax Act</i>	w	and 2017 expense determination
	•	\$2,818.89 in 2015 and increasing by 2.50% per year for year-end disclosure December 31, 2015
	а	and 2016 expense determination
Mortality table	• 2	2014 Private Sector Canadian Pensioners Mortality Table
Mortality improvements	•	Fully generational using CPM Improvement Scale B
Mortality table size adjustments	₹	
Termination	•	See tables of sample rates
Retirement age for active members	•	See table of sample rates
Expenses	•	Implicit in long-term rate of return on assets
Percentage with spouse at retirement	•	80% married
Spousal age difference	∀ •	A male is assumed to be three years older than his female spouse

There have been no changes in actuarial assumptions since the prior valuation other than the changes to the principal assumptions shown in the table above.

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Sample rates from the age related tables are summarized below:

Age Based Merit and Promotion Scale

Age	Non-SME	SME
<30	3.50%	3.75%
30-39	2.50%	2.75%
40-49	1.50%	1.75%
50-54	0.50%	1.25%
55+	0.50%	0.75%

Termination

Age	Male	Female
20	2.0%	2.0%
25	2.0%	2.0%
30	2.0%	2.0%
35	4.6%	4.6%
40	3.0%	3.0%
45	2.5%	2.5%
50	1.5%	1.5%
54	1.1%	1.1%

¹ Senior Management Employee ("SME")

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

Retirement

	Not Eligible for	Eligible for Unreduced
Age	Unreduced	
22	2.0%	17.5%
56	2.0%	17.5%
22	2.0%	17.5%
58	2.0%	17.5%
29	2.0%	17.5%
09	17.5%	17.5%
61	17.5%	17.5%
62	17.5%	17.5%
63	17.5%	17.5%
64	17.5%	17.5%
65	20.0%	20.0%
99	20.0%	20.0%
29	20.0%	20.0%
89	20.0%	20.0%
69	20.0%	20.0%
70+	100.0%	100.0%

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

Rationale for Significant Economic and Demographic Assumptions as at December 31, 2016

We assisted EGD in developing their demographic assumptions to measure pension obligations as at December 31, 2016 and the rationale behind such assumptions is the same as described in the Funding Reports.

A rationale for each of the significant economic assumptions used to measure pension obligations as at December 31, 2016 other than prescribed assumptions is provided below:

- from a yield to maturity curve based on actual AA corporate bond yield data for short term yields and extrapolated data for longer terms. November 2016). Under the Mercer Model, the plans' projected benefit payments are matched against a series of spot rates derived The discount rate was determined based on the high quality corporate bond yield curve derived from the Mercer Model (revised
- The inflation assumption reflects the best estimate of future price inflation considering current market conditions and taking into account the mid-point of the inflation target set by Bank of Canada.
- The YMPE and ITA limit increase assumption reflects the best estimate assumption of inflation plus an allowance of 0.50% for the effects of real economic growth and productivity gains in Canada.
- The expected rate of return on plan assets is based on:
- The median simulated investment return using estimated returns for each major asset class consistent with market conditions on the measurement date, the expected time horizon over which benefits are expected to be paid, and the target asset mix specified in the plan's investment policy.
- management. Such fees were determined as the difference between the provision for total investment expenses and the Additional returns assumed to be achievable due to active equity management, equal to the fees related to active equity hypothetical fees that would be incurred for passive management of all assets.
- Implicit provision for expenses determined as the average rate of investment and non-investment expenses paid from the fund over recent years.
- The pensionable earnings increase assumption is based on an experience study that was conducted in 2014 considering increases over the years 2009 to 2013 and on EGD's expectations.

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

APPENDIX E

Actuarial Methods

attributed to years of service, taking into consideration future salary increases and the plan's benefit allocation formula. Thus, the estimated Benefit obligations are estimated using the Projected Unit Credit method. Under this method each participant's benefits under the plan are total pension to which each participant is expected to become entitled at retirement is broken down into units, each associated with a year of past or future credited service.

A description of the calculation follows:

- An individual's estimated attributed benefit for valuation purposes related to a particular separation date (for example, expected date of retirement, leaving service or death) is the benefit described under the plan based on credited service as at the measurement date, I determined using the projected salary that would be used in the calculation estimate of the benefit on the expected separation date.
- The benefit attributed to an individual's service during a plan year is the excess of the attributed benefit for valuation purposes at the end of the plan year over the attributed benefit for valuation purposes at the beginning of the plan year. Both attributed benefits are estimated from the same projections to the various anticipated separation dates.
- plan year, and the service cost is the present value of the benefit attributed to the year of service in the plan year. If multiple decrements are used, the benefit obligation and the service cost for an individual are the sum of the component benefit obligations and service costs An individual's estimated benefit obligation is the present value of the attributed benefit for valuation purposes at the beginning of the associated with the various anticipated separation dates. Such benefit obligations and service costs reflect the estimated attributed benefits and the probability of the individual separating on those dates.
- The vested benefit obligation is based on the expected date of separation, and an individual's projected benefit obligation is constrained to be not less than his or her accumulated benefit obligation

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

multiple decrements are used, the present values take into account the probability of the individual leaving employment at the various measurement date, and the service cost is the total present value of the individuals' benefits attributable to service during the year. In all cases, the benefit obligation is the total present value of the individuals' attributed benefits for valuation purposes at the anticipated separation dates.

Valuation Procedures

The following approximations have been made in applying this method:

projection involves rolling forward the results at the earlier date allowing for interest on the liabilities, the accrual of further benefits by active Projection of obligations from valuation date to year-end measurement date: The benefit obligations at the year end December 31, members, the actual benefits payments paid out and the effect of any changes in the actuarial assumptions. We have assumed that all other experience during the projection, apart from investment returns, contributions, benefit payments, administration expenses and 2016 have been based on a projection of the results of the actuarial funding valuations of the plans as at December 31, 2015. This insurance premiums, has been in line with the assumptions made at the start of the year.

Accounting Policies

The accounting policies in cases where EGD has a choice of policy are set out below.

There have been no changes to the accounting methods or accounting policies since the prior valuation.

Materiality threshold: EGD has not instructed us to make any adjustments to the valuation procedures described in order to satisfy its materiality threshold.

contributions and benefit payments that will be made during the period. It is only updated to allow for subsequent experience in the event of reporting period using actuarial assumptions fixed at the start of the period, including assumptions about expected pensionable salaries, Net periodic benefit cost measurement: The net periodic benefit cost charged to profit or loss is budgeted for at the start of each material changes.

Interest on service cost: The current service cost includes all interest on the service cost during the reporting period.

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ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

Administration expenses: An allowance for administration expenses is included in the pension expense by making a deduction from the expected rate of return on plan assets. Discretionary benefits: No allowance is made in the benefit obligation for discretionary benefits on the grounds that there is no substantive commitment to provide such benefits. Therefore any benefit increases that are awarded on a discretionary basis are accounted for as a prior service cost.

Significant events: No significant events have occurred during the reporting period that require accounting policy decisions.

Amortization method and periods: The cumulative gains and losses in excess of 10% of the greater of the beginning of year benefit obligation or market related value of plan assets are amortized over the expected average remaining working lives of the employees participating in the plan.

Accounting Estimates

Accounting estimates as they apply to the split rate approach as at December 31, 2016 are as follows:

Discount rate setting process: For each plan, the discount rate on the benefit obligation is estimated as the single equivalent rate such that the present value of the benefit obligation cash flows using the single rate equals the present value of those cash flows using the Mercer Yield Curve as of the measurement date.

The same process is applied to the service cost cash flows to determine the discount rate associated with the service cost. Separate discount rates are determined for the benefit obligations and service costs.

Determination of benefit obligations and service costs: The benefit obligations and service cost are each calculated using their separate discount rates described above. Prior to December 31, 2016, EGD had used a single liability-weighted discount rate for all Canadian pension and non-pension plans combined, and rounded to the nearest 10 basis points.

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016 Calculation of interest: Interest on benefit obligations, for purposes of determining the interest cost, and the interest on the service cost are calculated by applying interest to the present value of the payment expected at each payment date. For this purpose, interest is determined using the same spot rate used to determine the present value of the associated payment.

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ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

APPENDIX F

EGD RPP Disclosure Information - By Employer

		•		Fuhridge Gas	
		Enbridge Gas	-	New Brunswick	
		Distribution Inc.	Gazifere Inc.	luc.	Total
Ä	Change in benefit obligation				
	Benefit obligation at beginning of year	965,810,400	18,501,800	11,689,400	996,001,600
	Service cost	29,210,000	889,700	848,000	30,947,700
	Interest cost	33,069,300	628,000	404,100	34,101,400
	Employee contributions				
	Special termination benefits				
	Benefits paid from the plan	(43,782,600)	(610,300)	(365,500)	(44,758,400)
	Net transfer in/(out)	510,000	(200,000)	(1,000)	
	Actuarial loss (gain)	47,919,300	1,371,800	809,900	50,101,000
	Benefit obligation at end of year	1,032,736,400	20,272,000	13,384,900	1,066,393,300
œ	Change in plan assets				
	Fair value of plan assets at beginning of year	913,463,600	14,771,800	8,860,400	937,095,800
	Actual return on plan assets	69,326,500	1,114,400	672,500	71,113,400
	Employer contributions to plan				
	Employee contributions				
	Benefits paid	(43,782,600)	(610,300)	(365,500)	(44,758,400)
	DC contributions paid from DB surplus		•		•
	Net transfer in (out)	354,900	(354,000)	(006)	•
	Fair value of plan assets at end of year	939,362,400	14,921,900	9,166,500	963,450,800
Ċ	Reconciliation of funded status				
	Fair value of plan assets	939,362,400	14,921,900	9,166,500	963,450,800
	Benefit obligations	1,032,736,400	20,272,000	13,384,900	1,066,393,300
	Net asset (obligation) recognized in statement of financial position	(93,374,000)	(5,350,100)	(4,218,400)	(102,942,500)
Ġ	Amounts recognized on the consolidated balance sheet position consists of Noncurrent assets	,	,	,	,
	Current liabilities	- 10000			- 1000
	Noncurrentulabilities Net asset (obligation) recognized in statement of financial position	(93,374,000) (93,374,000)	(5,350,100) (5,350,100)	(4,218,400) (4,218,400)	(102,942,500)

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

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ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

Enbridge Gas New Brunswick Distribution Inc. Distribution Inc. Output Di	(5,790,200) (2,827,900)	(297,466,300) (5,790,200) (2,827,900) (306,084,400) 204,092,300 440,100 (1,390,500) 203,141,900	(93,374,000) (5,350,100) (4,218,400) (102,942,500)		889,700 848,000	628,000 404,100	(38,U11,80J) (323,30J) (38,50Z) (38,50Z) (38,50Z)		13,610,600 228,600 79,100 13,918,300	17,878,100 822,400 764,600 19,465,100		2,021 81 79 2,181			36,604,600 1,181,300 704,000 38,489,900) (228,600) (79,100)	952,700 624,900	40,872,100 1,775,100 1,389,500 44,036,700	verthe next fiscal year		(14 661 800) (285 400) (139 400) (15 086 600)	(500, 100)
cognized in statement of financial position		Accumulated other comprehensive income (loss) Accumulated contributions in excess of net periodic benefit cost 204,	Net asset (obligation) recognized in statement of financial position (93,	et periodic benefit cost		Interest cost 33,	ion (asset)	Amortization of prior service cost	Amortization of net (gain) loss	Net periodic benefit cost	Headcounts for expense ¹	EGD RPP - DB service cost provision	¹ Note the 2016 expense is based on headcount as at December 31, 2014	Changes recognized in other comprehensive income Changes in plan assets and benefit obligations recognized in other comprehensive income New prior service cost		Amounts recognized as a component of net periodic benefit cost Amortization or curtailment recognition of prior service credit (cost)			Total recognized in net periodic benefit and other comprehensive loss 40,	Estimated amounts that will be amortized from accumulated other comprehensive income over the next fiscal year	Initial net asset (obligation) Prior service credit (cost)		

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ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

				Enbridge Gas	
		Distribution Inc.	Gazifere Inc.	New Brunswick Inc.	Total
İ	Weighted-average assumptions to determine benefit obligations				
	Discount rate	3.92%	3.92%	3.92%	3.92%
	Rate of compensation increase	3.46%	3.46%	3.46%	3.46%
	Measurement date	31-Dec-2016	31-Dec-2016	31-Dec-2016	31-Dec-2016
	Assumptions to determine net cost				
	Effective discount rate for benefit obliqations	4.20%	4.20%	4.20%	4.20%
	Effective rate for interest on benefit obligations	3.50%	3.50%	3.50%	3.50%
	Effective rate for service cost	4.30%	4.30%	4.30%	4.30%
	Effective rate for interest on service cost	4.02%	4.02%	4.02%	4.02%
	Expected return on assets	6.50%	6.50%	6.50%	9.20%
	Rate of compensation increase	3.43%	3.43%	3.43%	3.43%
٦.	Additional year-end information				
	Required information for all defined benefit plans				
	Accum ulated benefit obligation	950,275,000	17,147,500	10,816,300	978,238,800
	Sensitivity to key assumptions for pension plans				
	Sensitivity to key as sumptions				
	Certaining to hely assuming the second secon				
	a. Hair a percent decrease in expected return on assets				
	i. Effect on pension expense	4,462,400	71,100	43,600	4,577,100
	ii. Effect on year-end benefit obligation				
	b. Half a percent decrease in discount rate				
	i. Effect on pension expense	6,140,400	198,700	175,100	6,514,200
	ii. Effect on year-end benefit obligation	82,277,400	1,966,600	1,445,100	85,689,100
	c. Half a percent decrease in rate of salary increase				
	i. Effect on pension expense	(2,705,100)	(103,500)	(94,600)	(2,903,200)
	ii. Effect on year-end benefit obligation	(13,699,300)	(538,000)	(465,300)	(14,702,600)
작	Additional year-end information for plans with accumulated benefit obligations				
	in excess of plan assets				
	Projected benefit obligation	1,032,736,400	20,272,000	13,384,900	
	Accum ulated benefit obligation	950,275,000	17,147,500	10,816,300	
	Fair value of plan assets	939,362,400	14,921,900	9,166,500	
	The aggregate of results on an individual basis will not match the total plan				
نـ	Additional year-end information for plans with projected benefit obligations				
	in excess of plan assets				
	Projected benefit obligation	1,032,736,400	20,272,000	13,384,900	1,066,393,300

The aggregate of results on an individual basis will not match the total plan

ASC 715 (US GAAP)
ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

	Enbridge Gas Distribution Inc.	<u>N</u> Gazifere Inc.	New Brunswick Inc.	Total
Cash flows				
Projected company contributions in respect of service cost for following fiscal year	vice cost for following fis cal year			
31-Dec-2017:	21,867,100	667,100	601,000	23,135,200
31-Dec-2018:	22,617,100	000'069	621,600	23,928,700
31-Dec-2019:	23,392,900	713,700	643,000	24,749,600
31-Dec-2020:	24,195,200	738,200	000'599	25,598,400
31-Dec-2021:	25,025,100	763,500	082,800	26,476,400
31-Dec-2022:	25,883,500	789,700	711,400	27,384,600
31-Dec-2023:	26,771,300	816,700	735,800	28,323,800
31-Dec-2024:	27,689,600	844,800	761,100	29,295,500
31-Dec-2025:	28,639,300	873,700	787,200	30,300,200
31-Dec-2026:	29,621,700	903,700	814,200	31,339,600
Projected company contributions in respect of sp	respect of special payments for following fiscal year			
31-Dec-2017:	10,611,800	386,500	273,600	11,271,900
31-Dec-2018:	10,592,300	385,800	273,100	11,251,200
31-Dec-2019:	10,572,100	385,100	272,600	11,229,800
31-Dec-2020:	•		•	•
31-Dec-2021:		•	•	•
31-Dec-2022:	•		•	
31-Dec-2023:			•	
31-Dec-2024:		•	•	•
31-Dec-2025:		•	•	•
31-Dec-2026:		ı	1	ı
Total projected company DB contributions for following fiscal year	wing fiscal year			
31-Dec-2017:	32,478,900	1,053,600	874,600	34,407,100
31-Dec-2018:	33,209,400	1,075,800	894,700	35,179,900
31-Dec-2019:	33,965,000	1,098,800	915,600	35,979,400
31-Dec-2020:	24,195,200	738,200	000'599	25,598,400
31-Dec-2021:	25,025,100	763,500	084,800	26,476,400
31-Dec-2022:	25,883,500	789,700	711,400	27,384,600
31-Dec-2023:	26,771,300	816,700	735,800	28,323,800
31-Dec-2024:	27,689,600	844,800	761,100	29,295,500
31-Dec-2025:	28,639,300	873,700	787,200	30,300,200
31-Dec-2026 ·	001 100 00		000	

ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

	Total	47,646,200	48,873,200	50,161,300	51,544,800	53,066,000	288,254,900		222,607,000	(19,465,100)			•	•	•		•		203,141,900		•		•	•			•				1		
Enbridge Gas New Brunswick	lnc.	389.100	399,100	409,600	420,900	433,300	2,353,900		(626,000)	(764,600)			,		100		•		(1,390,500)		•			•							ı		
_	Gazifere Inc.	649,600	666,400	683,900	702,800	723,500	3,930,200		1,107,500	(822,400)			•	•	155.000	•			440,100				•	•			•		•	1	ı	1	
Enbridge Gas	Distribution Inc.	46,607,500	47,807,700	49,067,800	50,421,100	51,909,200	281,970,800		222,125,500	(17,878,100)			,	•	(155.100)				204,092,300				•			ve incom e		nings)			1		•
	Expected benefit payments for EVE	31-Dec-2017 :	31-Dec-2018:	31-Dec-2019:	31-Dec-2020:	31-Dec-2021 :	Next five years	Accumulated contributions in excess of net periodic benefit cost	Amount as of beginning of year	Net periodic pension (cost) income for fiscal year	Employer contributions made in fiscal year (excludes contributions made	between measurement year end and fiscal year end)	made between measurement vear end and fiscal year end)	FAS 88 (expense) income	Net intraplan transfers	Plan combinations	Adjustment to match local books	, Exchange rate adjustment	Amount as of end of year	Reconciliation of prior service cost (credit)	Amount as disclosed as of prior year end	Amounts recognized as a component of net periodic benefit cost	Amortization	Effect of curtailment	Total amount recognized as a component of net periodic benefit cost	Changes in plan assets and benefit obligations recognized in other comprehensive income	Plan amendments	Other changes (adjustment to accumulated comprehensive income, retained earnings)	Plan combinations	Difference between prior year end and beginning of current year	Total amount recognized as other change in accumulated other		Amount at end of year

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ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

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ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

	Enhridge Gas		Enbridge Gas	
	Distribution Inc.	Gazifere Inc.	lnc.	Total
Reconciliation of net (gain) loss				
Amount as disclosed as of prior year end	274,472,300	4,837,500	2,203,000	281,512,800
Amounts recognized as a component of net periodic benefit cost				
Amortization	(13,610,600)	(228,600)	(79,100)	(13,918,300)
Effect of settlement		•		
Total amount recognized as a component of net periodic benefit cost	(13,610,600)	(228,600)	(79,100)	(13,918,300)
Changes in plan assets and benefit ob ligations recognized in other comprehensive income	e income			
Liability experience	47,919,300	1,371,800	809,900	50, 101,000
Asset experience	(11,314,700)	(190,500)	(105,900)	(11,611,100)
Effect of curtailment	•		•	
Extraordinary event that adjusts assets	•	•	•	•
Total amount recognized as a change in plan assets and benefit obligations	36,604,600	1,181,300	704,000	38,489,900
Other changes (adjustment to accumulated comprehensive income, retained earnings)	ngs)			
Plan combinations	•	•	•	•
Adjustment to match local books				
Difference between prior year end and beginning of current year		1		•
Difference between calculated year-end gain/loss and amount using events				
that occurred during the year			•	
Total amount recognized as other change in accumulated other				
comprehensive income	•	•	•	•
Exchange rate adjustment			•	ı
Amount at end of year	297,466,300	5,790,200	2,827,900	306,084,400
	1	1		
Actual net return on assets assuming middle of period cash flows	%)././	7.80%	7.75%	7.11%
DC Current service cost	808,700	53,500	37,500	899,700
Projected DC current service cost for fiscal year ending:				
31-Dec-2017:	763,900	49,000	38,800	851,700
31-Dec-2018:	790,400	50,700	40,200	881,300
31-Dec-2019:	817,800	52,500	41,600	911,900
31-Dec-2020:	846,200	54,300	43,000	943,500
31-Dec-2021:	875,600	56,200	44,500	976,300
31-Dec-2022:	000'906	58,100	46,100	1,010,200
31-Dec-2023:	937,400	60,100	47,700	1,045,200
31-Dec-2024:	006'696	62,200	49,300	1,081,400
31-Dec-2025:	1,003,600	64,400	51,000	1,119,000
31-Dec-2026 :	1,038,400	66,600	52,800	1,157,800

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ASC 715 (US GAAP) ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016

The following table presents the estimated pension expense for the fiscal period ending December 31, 2017: **Enbridge Gas**

	Ephridge Gas		New Brinswick	
	Distribution Inc.	Gazifere Inc.	lnc.	Total
Components of net periodic benefit cost				
Current service cost (employer)	30,460,200	962,700	861,100	32,284,000
Interest cost	33,614,100	664,200	439,200	34,717,500
Expected return on plan assets	(60,599,400)	(983,100)	(611,600)	(62, 194, 100)
Amortization of transitional obligation (asset)	1			
Amortization of past service costs	ı	•		•
Amortization of net actuarial loss (gain)	14,661,800	285,400	139,400	15,086,600
Net periodic benefit cost	18,136,700	929,200	828,100	19,894,000
DC current service cost	763,900	49,000	38,800	851,700
Headcounts for expense ¹				
EGD RPP - DB	1,988	81	78	2,147
Assumptions to determine net cost				
Effective discount rate for benefit obligations	3.92%	3.92%	3.92%	3.92%
Effective rate for interest on benefit obligations	3.33%	3.33%	3.33%	3.33%
Effective rate for service cost	4.14%	4.14%	4.14%	4.14%
Effective rate for interest on service cost	3.85%	3.85%	3.85%	3.85%
Expected return on assets	6.50%	%05'9	6.50%	%05'9
Salary increase rate	3.46%	3.46%	3.46%	3.46%

¹ Note the 2017 expense is based on headcount as at December 31, 2015

ACTUARIAL VALUATION REPORT AS AT DECEMBER 31, 2016 ASC 715 (US GAAP)

ENBRIDGE GAS DISTRIBUTION INC. CONSOLIDATED TOTAL FOR ALL PLANS

APPENDIX G

Employer Certification

year 2017, prepared in accordance with US GAAP, of the following plans: EGD RPP, SERP, SSERP, I hereby certify that, to the best of my With respect to the Actuarial Valuation Report for fiscal year ending December 31, 2016, and estimated net periodic benefit cost for fiscal knowledge and belief:

- The membership data supplied to the actuary provides a complete and accurate description of all persons who are entitled to benefits under the terms of the plan for service up to the date of the valuation.
 - Copies of the official plan documents and of all amendments made up to December 31, 2016, have been supplied to the actuary All substantive commitments (in accordance with US GAAP) have been communicated to the actuary.

 - Accounting policies as adopted by EGD are those described in this report.
- The actuarial methods to be used for the purposes of the valuation are those described in this report.
- The management's best estimate assumptions for purposes of the valuations and the extrapolation of the financial position of the plan as at December 31, 2016, are those described in this report.
 - All events subsequent to the valuation that may have an impact on the results of the valuation or of a future valuation have been communicated to the actuary

Signed Name Title Date Signed JOL S Name F 93 Date

Mercer 222 - 3rd Avenue SW, Suite 1200 Calgary, Alberta T2P 0B4



Exhibit I.D1.EGDI.BOMA.30

Page 1 of 2

BOMA INTERROGATORY #30

INTERROGATORY

Ref: Exhibit D1, Tab 6, Schedule 2, p1

Please explain in line 3, the reduction in accrued pension and OPEB costs by \$5.4 million for the 2018 placeholder account of \$26.2 million. Please show the calculation.

RESPONSE

The 2018 placeholder value of \$26.2 million was previously estimated in 2013, and the reduction in accrued pension and OPEB costs is due to several significant factors:

- 1. a change in the approach for calculating the interest on benefit obligations and service costs ("split rate approach") for pension and OPEB plans;
- 2. changes in membership data and plan assets;
- 3. changes in the provisions of the pension plans; and
- 4. changes in the assumptions used to determine the pension costs.

A brief discussion on the material factors follows.

As of January 1, 2016, Enbridge chose to implement a split rate approach for purposes of determining the benefit obligations and service cost as well as a spot rate approach for the calculation of interest on these items in the determination of the net periodic benefit cost. Separate discount rates are determined for the benefit obligations and service cost. Interest on benefit obligations and service cost, for purposes of determining the interest cost is calculated by applying interest to the present value of the payment expected at each payment date. Prior to January 1, 2016 a single rate was used to determine all applicable pension and benefit cost values. This estimate refinement decreased the current service cost and interest cost components of pension and OPEB costs.

The 2018 placeholder values were projections based on membership data as at December 31, 2012 and asset data as at February 28, 2013 for the pension plans, and membership data as at September 1, 2012 for the OPEB Plan. The membership data and plan assets data has been updated as described in the Mercer Report.

Changes to the provisions of the pension plans have been described in the Mercer Report and further in the interrogatories. No additional explanation is included here.

Witnesses: Mercer

R. Small

Exhibit I.D1.EGDI.BOMA.30

Page 2 of 2

There were several changes to key assumptions which have decreased the pension cost including, but not limited to:

- The inflation rate decreased (decrease of 0.25%). This decreased the current service cost, interest cost and amortization components.
- Refinements to the termination and retirement rate tables. This decreased the current service cost, interest cost and amortization components, including increasing the period over which actuarial losses are amortized.
- The long-term expected return on assets assumption increased for some plans (increase of 0.50%). This increased the expected return on assets component (and decreases the accrual cost).

The decrease in EGDI's DC Expense is due to the new plan design changes taking effect January 1, 2018.

Witnesses: Mercer

R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.EP.6

Page 1 of 2

EP INTERROGATORY #6

INTERROGATORY

Reference: Exhibit D1Tab 2 Schedule 4 Page 4

Preamble: The company has completed a comparison of the metering data from the TCPL custody transfer meters and Enbridge's own check meters at the 38 Gate Stations where TCPL's system interconnects with the EGD system and determined that for the period of January 1, 2017 to July 31, 2017 there is a difference of 27.8 10⁶m³ or 0.75% of the total TCPL metered volume for that period.

- A). Please clarify if the 27.8 106m³ difference is in favour of EGD or TCPL.
- B). Is this finding consistent with historic data and with UAF estimates? Please discuss and provide data to support the discussion.
- C). Please provide a schedule that positions this finding relative to the delivered TCPL City Gate commodity and transportation costs.
- D). Please list the receipt points and volumes at which Enbridge receives gas, other than TCPL.
- E). Has EGD reviewed these deliver points for metering inconsistencies? If so please summarize the findings.

RESPONSE

- a) For the period January 1, 2017 to July 31, 2017 when comparing the daily metering difference between the TCPL custody meters and Enbridge's own check meters at the 38 gate stations where TCPL's system interconnects with the EGD system, the TCPL metered data is 27.8 10⁶ m³ higher than the Enbridge check metered data.
- b) As discussed in EGD's response to BOMA Interrogatory #21 in EB-2017-0102 (Exhibit I.B.EGDI.BOMA.21 page 2 of 3), this information is consistent with the information compiled for the 2016 calendar year whereby the TCPL custody meters recorded a higher volume of 37.9 10⁶ m³ when compared to the Enbridge check meters. However, as discussed at Exhibit D1, Tab 2, Schedule 4, page 5 of 5, the .75% metering difference is within Measurement Canada specifications and may or may not represent any change in UAF and that further analysis is required.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.EP.6 Page 2 of 2

- c) The Company does not understand the question.
- d) Other than TCPL the primary receipt point where EGD receives gas is at Union Parkway. For the January 1, 2017 to July 31, 2017 period, EGD received 3,013.9 10⁶ m³.
- e) EGD is in the early stages of a review of the metering data regarding Union Parkway that is similar to the review being conducted regarding the TCPL metering information.

Exhibit I.D1.EGDI.EP.7

Page 1 of 1

EP INTERROGATORY #7

INTERROGATORY

Reference: Exhibit D1Tab 2 Schedule 11Page 3

- A). Please provide updates on the following Projects
 - Vaughan Mainline Expansion Project
 - Rover Pipeline
- B). Please provide the cost and other implications of any delays as related the 2018 Gas Supply Plan and the Dawn Access Agreement.

RESPONSE

a) TCPL posted a bulletin on October 2, 2018 regarding the Vaughan Mainline Expansion Project that stated:

The purpose of this bulletin is to provide further update on the status of the Vaughan Mainline Expansion project and the associated contracts supporting it. The Humber River crossing has now been successfully completed and the final tasks to complete the project are now underway. TransCanada is now able to place the underpinning contracts into service effective November 1, 2017.

According to the Rover Pipeline website as of November 3, 2018:

Phase 1A from Cadiz Township to our Defiance compressor station began operating on August 31, 2017. Phase 1B starting in Marion Township in Noble County, Ohio, to Cadiz Township in Harrison County, Ohio, is anticipated to be complete by the end of the year. The Rover Pipeline Project is expected to be in full service by the end of the first quarter of 2018.

b) The ability of TCPL to place the contracts into service that were underpinned by the Vaughan Mainline Expansion Project effective November 1, 2017 means there are no incremental cost implications to the 2018 Gas Supply Plan and the Dawn Access Agreement.

The Rover Pipeline project was not a part of EGD's 2018 Gas Supply Plan and therefore any delay in that project will not have any impact to EGD.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.EP.8 Page 1 of 1

EP INTERROGATORY #8

<u>INTERROGATORY</u>

Reference: Exhibit D1Tab 2 Schedule 11 Page 13; Exhibit D1, Tab 2, Schedule 3.

Preamble: At this time, as set out in the gas supply evidence in this proceeding Enbridge is planning to acquire between 2 and 3 PJ of additional storage in April 2018. Furthermore, from time to time, the Company will consider shorter term high deliverability seasonal exchanges that provide operational flexibility to meet winter demand.

Please indicate whether the proposed merger with Union will result in rationalization of Storage. Please discuss if/how this may affect the need for 2-3 PJ of incremental storage.

RESPONSE

The 2018 Gas Supply Plan for EGD was developed to meet the forecasted demand of the customers of EGD for the 2018 fiscal year. Enbridge and Union Gas will not be amalgamated during that time. A part of the 2018 Gas Supply Plan is to acquire incremental storage effective April 1, 2018 to serve the demand for EGD customers during the 2018 / 19 winter. Stated differently, EGD has identified a need for incremental storage in order to satisfy its Gas Supply Plan in 2018, and it does not consider that the pending amalgamation with Union Gas impacts that need..

Exhibit I.D1.EGDI.EP.9

Page 1 of 1

EP INTERROGATORY #9

INTERROGATORY

References: Exhibit D1Tab 4, Schedule 1, Page 1;

EB-2017-0102 Exhibit N1 Tab1 Sched le 1 Appendix A Page 16

Preamble: Any variance between the DSM amount included within 2018 Allowed Revenue and the actual DSM amounts incurred in 2018 will be recorded in the Demand Side Management Variance Account ("DSMVA"). Amounts recorded in the DSMVA will include variances in DSM program costs consistent with the Board's Filing Guidelines to the Demand Side Management Framework for Natural Gas Distributors (2015 to 2020). Even though this will be addressed in the ESM/DA EP has these questions.

- A). Please indicate if EGD has spent the approved 2016 and 2017 DSM budgets.
- B). Please provide an update and indicate in particular, if the residential sector budgets and targets were met in 2016 and based on YTD in 2017.
- C). Please provide an estimate for 2018 of the 2017 DSMCEIDA balance funds that represent the difference between Enbridge's approved 2017 DSM budget and the actual amount spent to achieve Enbridge's total 2017 Cumulative Cubic Metres ("CCM") of natural gas targets made up of all 100% CCM targets across all programs.

<u>RESPONSE</u>

- A) For the 2016 program year, the total OEB approved budget was \$56.4M and the total spend was \$55.6M. For the 2017 program year, the total OEB approved budget is \$62.9M and the 2017 year end results will be released when finalized as part of the 2017 Draft Annual Report that will typically be filed in Q2 of 2018.
- B) The residential sector budgets and targets were met in 2016. Detailed residential sector data for 2016 will be released as part of the Enbridge 2016 Draft Annual Report on Nov. 16/17. Details related to 2017 residential sector results have not yet been finalized and will be released as part of the Enbridge 2017 Draft Annual Report.
- C) Enbridge is not in a positon to accurately predict information related to the 2017 DSMCEIDA balance until the finalization of results and the release of the 2017 Draft Annual Report.

Witnesses: E. Reimer

R. Small J. Tideman

Exhibit I.D1.EGDI.FRPO.5

Page 1 of 2

FRPO INTERROGATORY #5

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, page 4

Preamble: We would like to understand EGD's approach to contingency planning that lead to the decision to contract for additional capacity from Chicago on Vector to replace the delayed capacity on Nexus. The above reference contains the following: "In order to mitigate the impact of the NEXUS in-service delay, Enbridge will continue to fill its Vector capacity with supply from Chicago until the contracted capacity on NEXUS comes into service. For the purposes of 2018 the Company is proposing that any variances associated with a delay will be captured as a part of the 2018 PGVA."

How much capacity was purchased from Chicago on Vector to replace the Nexus capacity?

- a) Please provide a schedule which shows the incremental impact of contracting for supply on Vector for the quantity contracted.
 - Please ensure any costs associated with mitigating Dominion supply arranged for Nexus and any incremental pipeline costs are included but highlighted separately.
 - ii) Who will bear responsibility for the above mitigation costs in i)?
- b) What is the forecasted landed cost of the supply at Dawn of the incremental Vector capacity in C\$/GJ using the July 1, 2017 QRAM prices for each month in the timeframe that has been contracted for?
 - i) Using the same July 1, 2017, what is the forecasted cost for Dawn-landed supply for each of those same months?
- c) How was the decision to contract for incremental Vector capacity arrived at versus Dawn purchases?
 - i) Please provide the quantitative and potentially qualitative analysis including forecasted costs supporting this approach.
- d) In addition to Board Staff IR 7c), why were these costs not evidenced in this proceeding as opposed to deferring to the mechanistic QRAM proceeding?

Exhibit I.D1.EGDI.FRPO.5

Page 2 of 2

RESPONSE

a), b) & c) EGD did not contract for incremental capacity on Vector. EGD currently has two transportation contracts with Vector Pipeline for a total of 175,000 Mmbtu/day. Prior to June 1, 2016 the contracts were for 96,000 Mmbtu/day and for 79,000 Mmbtu/day with primary receipt points at the Alliance/Northern Border interconnect on the Vector system and a primary delivery point at the Dawn interconnect. As of June 1, 2016, EGD restructured its contracts with Vector such that 65,000 Mmbtu/day would flow from Alliance/Northern Border to Dawn and 110,000 Mmbtu from Alliance/Northern Border to Dawn. The purpose of the restructuring was to enable to conversion of the main receipt point on the second contract to go from Alliance/ Northern Border to the Milford Junction receipt point. The delivery point would remain at Dawn. In response to FRPO Interrogatory #2 in the July 2017 QRAM (EB-2017-0181 Exhibit I, Tab 1, Schedule 2) the Company stated:

The Company has contracted to transport 110,000 Dth per day on NEXUS from Kensington, Ohio to the Milford Junction interconnect with Vector. The Company will then use a portion of its existing 175,000 Dth per day of Vector capacity to transport the NEXUS supply from Milford Junction to Dawn. As part of the Company's risk management strategy, the Company has restructured its Vector agreement with a provision to coordinate the change of receipt point from Chicago to Milford Junction with the in-service date of NEXUS. As a result, if NEXUS is delayed, the Company will maintain its ability fill the Vector capacity designated for NEXUS supply with supply from Chicago.

EGD has not yet entered into any supply arrangements for supplies at Dominion South and as such does not have any supply costs to mitigate nor will Enbridge incur any Nexus Pipeline costs until the pipeline is in-service.

As mentioned above the Vector capacity is not incremental and therefore a cost comparison of incremental Chicago supply versus Dawn supply is not warranted.

d) At the time the 2018 Gas Cost budget was prepared, EGD was aware that there would be a delay in the in-service date of the Nexus Pipeline until 2018. However, the length of the delay was unknown (i.e., January 1, February 1, March 1 etc.). Rather than speculating on the timing of the in-service date, the Company chose to assume a January 1/18 start. Please note that if the Company had assumed a date other than January 1/18 (i.e., March 1) and if the actual in-service date was different than forecast, then the Company would still record any variance associated with a timing variance in the 2018 PGVA.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.6

Page 1 of 1

FRPO INTERROGATORY #6

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, Page 5-6 and Schedule 7

Preamble: We would like to understand better the company's views of the impact on Direct Purchase customers. The above reference states: "The impact of Direct Purchase customers shifting from Western or Ontario T-Service to Dawn T-Service is twofold: firstly, peak day deliveries to the franchise area via Ontario T-Service customers will decline (Line 8 of the Peak Day Supply Mix schedule); secondly, the Company needs to increase volumes delivered to the franchise area to replace the decline in volume delivered by Ontario T-Service customers (currently that deficiency is mostly visible as an increase in Peaking Service in Line 11 of Schedule 7). The expectation is that over time as the Dawn T-Service option becomes more prevalent then it will no longer be necessary for new Direct Purchase customers to demonstrate firm transportation commitments. However, the Company reserves the right to review this on a case by case basis should the Ontario T-Service option begin to increase or should other service types become available in the future."

Line 7 evidences a reduction in peaking service in 2018 from the 2017 Application.

- a) Please provide any update to the values contained in Schedule 7.
- b) What are the expected cost consequences of any such change?

RESPONSE

Please see response to Board Staff Interrogatory #8, at I.D1.EGDI.STAFF.8.

Exhibit I.D1.EGDI.FRPO.7

Page 1 of 2

FRPO INTERROGATORY #7

<u>INTERROGATORY</u>

REF: Exhibit D1, Tab 2, Schedule 3, Page 5-6 and Schedule 7

Preamble: We would like to understand better the company's views of the impact on Direct Purchase customers. The above reference states: "The impact of Direct Purchase customers shifting from Western or Ontario T-Service to Dawn T-Service is twofold: firstly, peak day deliveries to the franchise area via Ontario T-Service customers will decline (Line 8 of the Peak Day Supply Mix schedule); secondly, the Company needs to increase volumes delivered to the franchise area to replace the decline in volume delivered by Ontario T-Service customers (currently that deficiency is mostly visible as an increase in Peaking Service in Line 11 of Schedule 7). The expectation is that over time as the Dawn T-Service option becomes more prevalent then it will no longer be necessary for new Direct Purchase customers to demonstrate firm transportation commitments. However, the Company reserves the right to review this on a case by case basis should the Ontario T-Service option begin to increase or should other service types become available in the future."

What is Enbridge's current policy for review of existing customers demonstrating firm transportation commitments?

- a) What criteria is used for acceptability for existing or new customers?
- b) What criteria would provide a threshold to eliminate this requirement?

RESPONSE

- a) The current criteria, as set out in Rider A of the Rate Handbook, is that FT capacity to be turned back must be replaced with alternative, contracted firm transportation of equivalent quality to the TCPL FT capacity. In the past, the Company has required customers to provide proof that the capacity has been contracted in their name.
- b) As mentioned in the preamble set out above, as customers convert to the Dawn T-Service option then it is possible that the criteria to demonstrate firm transportation for those service types could be eliminated due to the liquidity of the Dawn hub. The expectation is that the conversion to Dawn T-Service will be complete by the end of 2018 and therefore, EGD suggests revisiting this criteria at that time.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.7 Page 2 of 2

For customers who wish to remain under the Ontario T-Service option, the Company suggests the current criteria remain in place, with the caveat that EGD would be prepared to review on a case by case basis and allow a customer using a third party's transportation to provide a written guarantee of delivery to EGD in place of requiring that customer to show its own firm transportation.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.8 Page 1 of 1

FRPO INTERROGATORY #8

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, page 6 and Schedules 7&9 and EB-2015-0114 Exhibit D1, Tab 2, Schedule 6

Preamble: We would like to understand better the shift in EGD's transportation contract portfolio as it moves from Long-haul to Short-haul. A comparison of the Schedule for 2016 rates with the two Schedules referenced provides a comparison showing the amount of Long-haul reduction over the last few years.

Please confirm that the Peak Day demand for:

- a) 2015 was met, in part, by 795,165 GJ of FT Long-haul.
- b) 2018 will be met, in part, by 265,000 GJ of FT Long-haul.

RESPONSE

- a) Confirmed.
- b) Confirmed.

Exhibit I.D1.EGDI.FRPO.9

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FRPO INTERROGATORY #9

<u>INTERROGATORY</u>

REF: Exhibit D1, Tab 2, Schedule 3, page 6 and Schedules 7&9 and EB-2015-0114 Exhibit D1, Tab 2, Schedule 6

Preamble: We would like to understand better the shift in EGD's transportation contract portfolio as it moves from Long-haul to Short-haul. A comparison of the Schedule for 2016 rates with the two Schedules referenced provides a comparison showing the amount of Long-haul reduction over the last few years.

Please confirm that the total amount of westerly capacity held by EGD from Parkway to Dawn is the 436,586 GJ/day, a total of C1 Westerly and M12-X.

- a) Please confirm that this value has remained constant from 2015 to 2018. If not, please correct.
- b) Please confirm that this westerly capacity is predominantly used to move excess infranchise deliveries back to storage at Dawn.
- c) Please provide the peak day nomination for westerly flow from Parkway to Dawn in 2017.
- d) Given the significant reduction in Long-haul TCPL service delivered in-franchise, please explain why EGD has not reduced its westerly capacity from Parkway to Dawn?

RESPONSE

- a) Confirmed. The C1 contract for 236,586GJ/day and the M12X contract for 200,000 GJ / day have been in place over this time period.
- b) Confirmed.
- c) On August 4 / 17 the Company requested capacity overrun on its C1 contract which was authorized by Union and actually flowed 268,922 GJs.
- d) The Company has provided notice that it intends to terminate the C1 contract on the current expiry date of March 31, 2019.

Exhibit I.D1.EGDI.FRPO.10

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FRPO INTERROGATORY #10

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, page 8

Preamble: We would like to understand better the high deliverability seasonal exchanges referred to in the following evidence from the above reference: "The Company is also reviewing shorter term high deliverability seasonal exchanges to meet a winter Dawn requirement. These hybrid arrangements provide economic benefit to customers and offer enhanced operational flexibility."

At a high level, please describe these high deliverability seasonal exchanges including an explanation of the hybrid aspect of these arrangements.

- a) Please provide a brief summary of the anticipated economic benefits to customers and enhanced operational flexibility.
- b) Please compare and contrast these arrangements with a simple forward purchase of gas at Dawn delivered during the winter months that is purchased in a prior period (e.g., around July 1st with the forward prices available through QRAM processing).
- c) For the last four years starting July 2013/January 2014 and for this year July 2017/ January 2018, using information that was available in the July 1 QRAM filings, please provide the monthly prices forecasted for landed gas at Dawn for July and January of each respective year.

RESPONSE

a) Operational flexibility is gained through the utility being able to call on the high deliverability exchange as it is required throughout the winter, which enhances the Company's ability to manage day-to-day load balancing during the volatile winter months. Conversely, a traditional exchange deal would not provide the ability to change deliveries from day to day.

The first economic benefit is in the ability to purchase cheaper summer supply for use in the winter months when supply is expected to be more expensive. The second expected economic benefit comes from the flexibility to complete the exchange in the winter using variable daily nominations which would potentially offset commodity costs on some of the highest priced days of the winter. One example to demonstrate this is:

Exhibit I.D1.EGDI.FRPO.10

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if in the Company's winter planning meetings a short term period of colder than budget weather is expected, the higher deliverability exchange deal could be called upon on those days instead of going to the market to purchase supply on a daily basis. Then after the short term colder than budget period ends, the remaining supply left on the exchange deal can be reserved for another expected colder than budget period.

- b) As the Company explains in response to FRPO # 17, entering into a supply arrangement with a counter party in July for January delivery is not the issue. EGD is unaware of any supplier who would be prepared to sell supply in a forward market at a price equal to current prices. A January purchase would be based upon either the daily index reported in the month of January or the January monthly index once the January contract closes. It may be possible to find a supplier prepared to sell a fixed price contract but the price payable for that supply would still be based off of a forward price curve i.e. the current price that a January contract would be trading for, and most likely at a premium.
- c) Below is the July and January Dawn pricing data for the years requested. The unit rates are expressed in US\$ /Mmbtu. Listed below is the US exchange rate applicable to those months and a CDN \$/GJ equivalent. Please note the Company only recently began including Dawn pricing on the QRAM exhibit titled "Monthly Pricing Information." For those prior years where the information was not shown the unit rates were based over the same 21-day period

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	21 Day	21 Day	
	Average	Average	
	Dawn	US Exchange	
	\$US/MMBtu	\$CAD/\$US	Canadian \$/GJ
Jul-13	4.4481	1.0228	4.3122
Jan-14	4.7218	1.0272	4.5973
Jul-14	4.7070	1.0907	4.8659
Jan-15	5.0219	1.0956	5.2149
Jul-15	3.0232	1.2188	3.4924
Jan-16	3.6007	1.2216	4.1689
Jul-16	2.2269	1.2973	2.7382
Jan-17	3.3460	1.2968	4.1129
Jul-17	3.2282	1.3575	4.1536
Jan-18	3.6617	1.3527	4.6947

Exhibit I.D1.EGDI.FRPO.11

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FRPO INTERROGATORY #11

<u>INTERROGATORY</u>

REF: Exhibit D1, Tab 2, Schedule 3, page 9, Table 1 and page 12, paragraph 35

Preamble: We would like to understand better the consideration of the total cost of supply from different sources. Paragraph 35 states: "The shift from long haul capacity to short haul capacity is contributing to a lower cost gas supply portfolio, on a per unit basis. Landed cost was considered in all contracting decisions made for 2017, weighed against the other three gas supply principles."

For each of the sources of gas in Table 1, please provide the landed cost on a C\$/GJ basis.

- a) Does this landed cost take into account redelivery to EGD franchise from storage in the winter (i.e., storage cost, M12, STS, etc.)?
 - i) If yes, please describe how those costs are calculated and provide the comparative costs for each source.
 - ii) If not, please describe how Enbridge makes the determination of buying at a Hub and piping to Ontario versus buying similar quantities landed in-franchise or at Dawn in the winter.

RESPONSE

See the table below for a landed cost analysis of most supply sources found in Table 1. The following sources of supply were not included in the table below:

- 1. Ontario Production: this supply source is de minimis and is not considered when evaluating incremental transportation capacity.
- Peaking: this is a callable supply arrangement used to meet near-design day demand requirements and is not considered when evaluating incremental transportation capacity.

Exhibit I.D1.EGDI.FRPO.11

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Summary of Landed Cost Analysis: Delivered to Enbridge CDA (\$C/GJ)

Pipeline/Service	Path	Pricing Point	2018
TCPL/FT-LH	Empress-to-Enbridge CDA	Empress	4.650
TCPL/FT-SH	Niagara-to-Enbridge Parkway CDA	Niagara	3.062
Union/M12 & TCPL/FT-SH	Dawn-to-Union Parkway Belt-to-Enbridge CDA	Dawn	3.836
Vector/FT-1 & Union/M12 & TCPL/FT-SH	Chicago-to-Dawn-to-Parkway-to-Enbridge CDA	Chicago	4.103
NEVLIC 8 LIST - AMAZ 8 TODI /FT CII /P)	Dominion South-to-Milford Junction-to-Dawn-to-	D i C th	4.535
NEXUS & Union/M12 & TCPL/FT-SH (Base)	Parkway-to-Enbridge CDA	Dominion South	4.525

Average Commodity Prices (\$C/GJ)

Pricing Point	2018
Chicago	3.402
Dawn	3.478
Dominion South	3.049
Empress	2.521
Niagara	2.810

Average Foreign Exchange Rate

	2018
C\$/US\$	1.259

Average Demand Charge (C\$/GJ)

Pipeline	Path	2018
TCPL	Empress-to-Enbridge CDA	1.827
TCPL	Niagara Falls-to-Enbridge Parkway CDA	0.238
TCPL	Union Parkway-to-Enbridge CDA	0.199
UNION M12	Dawn-to-Parkway/EGT	0.112
Vector	Chicago-to-St. Clair	0.286
Vector	St. Clair-to-Dawn	0.019
NEXUS (Base)	Dominion South-to-Milford Junction	0.834
NEXUS (Base)	Milford Junction-to-Dawn	0.191

Average Abandonment/ACA Charge (C\$/GJ)

Pipeline	Path	2018
TCPL	Empress-to-Enbridge CDA	0.1951
TCPL	Niagara Falls-to-Enbridge Parkway CDA	0.0100
TCPL	Union Parkway-to-Enbridge CDA	0.0067
UNION M12	Dawn-to-Parkway/EGT	0.0000
Vector	Chicago-to-St. Clair	0.0017
Vector	St. Clair-to-Dawn	0.0004
NEXUS	Dominion South-to-Milford Junction	0.0017

Average Fuel Ratio

Pipeline	Path	2018
TCPL	Empress-to-Enbridge CDA	4.261%
TCPL	Niagara Falls-to-Enbridge Parkway CDA	0.248%
TCPL	Union Parkway-to-Enbridge CDA	0.186%
UNION M12	Dawn-to-Parkway/EGT	0.761%
Vector	Chicago-to-St. Clair	1.014%
Vector	St. Clair-to-Dawn	0.000%
NEXUS (Base)	Dominion South-to-Milford Junction	2.100%
NEXUS (Base)	Milford Junction-to-Dawn	0.461%

Exhibit I.D1.EGDI.FRPO.11

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(a) When the Company prepares a landed cost analysis it includes the cost of the commodity plus the cost of the incremental transportation capacity required to deliver the gas to the franchise area. The Company will also consider: (1) the landed cost of the service relative to other available options, (2) the reliability of the service relative to existing services, (3) the diversity implications the service would have versus status quo, and (4) if the service would provide adequate flexibility for the portfolio.

Landed cost evaluations do not take into account redelivery to the EGD franchise from storage in the winter.

Whether gas is purchased at Dawn or withdrawn from storage it will require transportation on M12 so the cost of transportation is the same in both scenarios. In order to make a determination of whether or not to purchase incremental supplies at Dawn in the summer and storing that gas for withdrawal next winter versus waiting to purchase that supply at Dawn next winter an analysis would be as follows:

Forecasted Summer Dawn Price + Unit Cost of Storage + Carrying Cost vs Forecasted Winter Dawn Price.

Therefore, if the price spread between summer and winter prices at Dawn is greater than the value of storage then acquiring additional storage capacity would make it beneficial to acquire additional supplies in the summer versus waiting to buy that supply in the winter.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.12

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FRPO INTERROGATORY #12

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 3, page 10, paragraph 29.

Preamble: We would like to understand better the cost of storage that EGD is expecting to contract for. Paragraph 29 states: "Storage contracts for capacity with third party providers are valued at market based pricing. The magnitude of the contracted capacity and the term of the contracts vary such that every year Enbridge will enter the marketplace via an RFP process seeking to replace the contracted capacity scheduled to expire March 31 of that year. For purposes of the 2018 gas cost forecast, the Company has assumed the amount and value of storage set to expire be extended. As mentioned in paragraph 23 the Company intends to acquire an additional 2 to 3 PJ's of storage effective April 1, 2018. For gas cost purposes in 2018 the Company has assumed a value for this incremental storage equivalent to the current value of the storage contracts scheduled to expire March 31, 2018. Any variation between the assumed storage costs and the actual cost of storage acquired will be captured in the 2018 S&TDA."

Please provide the per GJ space cost for the existing contracts of expiring storage space differentiated by deliverability (ie., different cost for different levels of deliverability, if applicable)

- a) For any replacement storage that starts April 1, 2018 that has already been contracted for, please provide the per GJ space cost of the replacement contract(s) differentiated by deliverability (if applicable).
- b) For any new storage that has been contracted for starting April 1, 2018, please provide per GJ space cost of the new storage contract(s) differentiated by deliverability.
- c) From a published source, please provide the April-October and November-March strip prices C\$ /GJ at Dawn for the number of years that EGD is contracting for the replacement and/or new storage.

RESPONSE

Enbridge is not prepared to provide the requested cost and deliverability information about the expiring market based contracts, because it may impair Enbridge's ability to achieve the best results through an RFP to replace this capacity.

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a), b), c)

As of November 6, 2017 EGD has not issued an RFP for storage services commencing April 1, 2018.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.13

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FRPO INTERROGATORY #13

<u>INTERROGATORY</u>

REF: Exhibit D1, Tab 2, Schedule 6 and EB-2015-0114 Exhibit D, Tab 2, Schedule 6 and EB-2016-0215 Exhibit D, Tab 2, Schedule 6

Preamble: We would like to understand better the costs underpinning EGD existing Market-based Storage.

For the Market-based storage in Line 1.4 of Column 1, please provide the cost of the storage for Fiscal 2018 on a per GJ of storage space basis

- a) What is the average deliverability of the contracts whose costs are included.
- b) For the previous 2 applications referenced above, please provide the cost of the storage for Fiscal 2017 and Fiscal 2016 on a per GJ of storage basis and the average deliverability underpinning each.

RESPONSE

a) The forecast amount of \$18.9 million shown at Exhibit D1,Tab 2, Schedule 6, Item 1.4, in Column 1 was based upon an exchange rate of 1.3483 for those contracts payable in US funds and includes a forecast of \$1.2 million for the proposed increase in market-based storage effective April 1, 2018. For a comparison to prior years, this incremental amount should be removed from the \$18.9 million. As per Exhibit D1, Tab 2, Schedule 9, page 2 of 2, the Company has market-based storage contracts amounting to 24.4 PJ's of capacity (which excludes the proposed incremental storage) would result in an average cost of market-based storage of \$0.72 / GJ.

Also shown at Exhibit D1, Tab 2, Schedule 9, page 2 of 2 is the total maximum withdrawal for the third party storage contracts of 0.4 PJ's or 1.67%. The Company also identified those contracts which are deemed as Synthetic Storage which will have a lower cost than physical storage but also have a lot less deliverability. For example the three Synthetic Storage contracts identified have an average deliverability of 0.66% while the physical storage has an average deliverability of 1.90 %.

b) In 2017 (EB-2016-0215 Exhibit D1, Tab 2, Schedule 6), the annual forecast for market-based storage was \$16.8 million and was based upon an average exchange rate of 1.2959 for 24.4 PJ's or an average of \$ 0.69 / GJ for 1.67 % deliverability. In 2016

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(EB-2015-0114 Exhibit D1, Tab 2, Schedule 5), the annual forecast for third party storage was \$15.6 million and was based upon an average exchange rate of 1.2226 for 24.4 PJ's or an average of \$ 0.64/GJ for 1.67 % deliverability.

Exhibit I.D1.EGDI.FRPO.14

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FRPO INTERROGATORY #14

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 8, page 2

Preamble: We would like to understand better how EGD is executing its Dawn purchases.

For the Dawn Delivered Supplies in Row 2.5, for each month, please provide the amount of supply that it is planned to be contracted for the entire month at least:

- a) one month ahead of delivery.
- b) Six months ahead of delivery.

RESPONSE

As discussed at Exhibit D1, Tab 2, Schedule 3, page 7 of 15 the Company intends to satisfy its monthly Dawn requirement through seasonal, term and monthly RFPs as well as purchases on a daily basis. EGD states further that it needs to maintain a level of flexibility in its portfolio to be able to manage potential reductions in demand because of warmer than budgeted weather in the winter. Therefore, the Company will take a measured approached in contracting for its winter Dawn requirement.

Through two separate RFPs, EGD acquired 150,000 Mmbtu/day of supply for the November 1, 2017 to March 31, 2018 period. The Companyalso acquired 200,000 Mmbtu/day for the December 1, 2017 to February 28, 2018 period through two separate RFPs. The remaining requirement will be acquired through monthly RFPs or daily purchases. determined closer to the time of the purchase requirement.

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FRPO INTERROGATORY #15

<u>INTERROGATORY</u>

REF: Exhibit D1, Tab 2, Schedule 9, page 2

Preamble: We would like to understand better the cost of synthetic storage.

For the three contracts listed, please provide the cost per GJ basis for each of the contracts and number of daily GJ's of winter or peak monthly supply provided by that contract.

<u>RESPONSE</u>

EGD declines to provide individual pricing data for market based storage contracts including those characterized as Synthetic Storage.

Synthetic storage arrangements are typically priced lower than physical storage arrangements because unlike physical transactions they do not offer any intra-day flexibility for injection or withdrawal. Typically, the daily injection amount is fixed at 1 / 214 of the contract capacity level and withdrawals are set at a daily rate equal to 1 / 151 of the contracted capacity. The contracts available during the winter of 2017/18 have an average deliverability of 0.66%.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.16 Page 1 of 1

FRPO INTERROGATORY #16

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, paragraphs 21 and 22

Preamble: We would like to understand better EGD's views on the Dawn LTFP project as it pertains to Gas Supply.

From a gas supply perspective, what are Enbridge's views on the impacts of Dawn LTFP on the Dawn market in terms of liquidity and price?

a) What position did EGD take on this project in the NEB proceeding on behalf of its ratepayers? Please explain.

RESPONSE

Please see response to SEC Interrogatory #6 (Exhibit I.D1.EGDI.SEC.6)

Exhibit I.D1.EGDI.FRPO.17

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FRPO INTERROGATORY #17

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, paragraph 37

Preamble: We would like to understand better the load balancing alternatives considered as part of the ICF study.

Did ICF evaluate the merits of advanced purchase (during the summer months) of monthly winter gas at Dawn as a substitute for storage acquisition? If not, why not?

- a) Drawn from actual values in responses provided to earlier interrogatories in our Information Requests above and QRAM data, please provide a detailed arithmetic assessment of the economic value of purchases of January and February gas purchased in June (at the time of the QRAM pricing) versus the cost of market-based storage currently in Enbridge's portfolio.
 - i) Please ensure that above ground availability of Dawn purchases are compared to deliverability available from storage.
 - ii) Please provide any reasons why the summer purchase of delivered winter gas should not be part of a diversified portfolio for a prudent LDC.

RESPONSE

To EGD's knowledge, ICF did not examine "advanced purchase" of winter gas at Dawn in place of storage. The Company assumes that the reason for this (as explained below) is because there would not be an expected pricing benefit to such advance purchases (the pricing would be based on the time when the gas is to be delivered rather than on the time when the contract is made).

In response to Board Staff Interrogatory #10 (Exhibit I.D1.EGDI.STAFF.10) the Company provided an excerpt from the ICF study that said:

In all of the scenarios, the increase in storage capacity allows Enbridge to purchase additional lower cost natural gas supply during off-peak periods for use during the winter when prices typically are higher.

EGD believes that with its increasing Dawn requirement throughout the winter that an alternative to buying gas in the winter would be to acquire storage and purchasing gas in

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.FRPO.17 Page 2 of 2

the summer which would be a preferred option assuming the value of storage would be at a price cheaper when comparing the Dawn summer/winter price spreads. Using the monthly pricing data provided in response to FRPO Interrogatory #10, at I.D1.EGDI.FRPO.10, it can be seen that such a price spread exists most if not all years. Therefore, if storage can be acquired at something less than that it would be beneficial to ratepayers.

EGD does not understand the scenario suggested in ii) above. If EGD were to approach a counter party in the summer of 2018 regarding winter deliveries in January 2019, then that counter party would price the supply based upon the forward January price curve. Alternatively the supplier could offer EGD with a fixed price for that supply which the counter party would base off of the forward curve and then they would lock in the price on their side using a risk management hedge which is something EGD is unable to do. Either way EGD would be essentially paying a winter index price for that supply.

Exhibit I.D1.EGDI.FRPO.18

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FRPO INTERROGATORY #18

INTERROGATORY

REF: Exhibit D1, Tab 2, Schedule 11, page 14

Preamble: We would like to understand better the cost consequences of accepting Direct Purchase deliveries at alternate points different from Empress or Dawn.

What was the forecasted final cost of the changes to Enbridge systems to facilitate Dawn Access?

- a) With the implementation of EGD's new Entrac/DP systems, what is the estimated cost of implementing a new receipt point for direct purchase?
- b) Was this estimate available and shared at the time of the Dawn Access proceeding?
- c) Based upon this estimated cost, notwithstanding the Dawn Access settlement agreement threshold of 50,000 GJ's, would EGD consider reducing the threshold to allow the receipt point capacity to build?
 - i) If not, why not?
 - ii) If so, what steps does EGD believe need to be taken to establish these alternate delivery points?

RESPONSE

a and b)

The forecasted final cost is approximately \$6.5 million. The estimate at the time of the Dawn Access proceeding was \$6 million. It is important to note at the time of the estimate it did not include the cost to implement the heat value conversion and interest costs. In addition, the estimate did not include the extended project time line due to resources being pulled away to implement GDAR changes and Cap and Trade. The cost to activate a new receipt point is approximately \$25,000.

c) EGD would be receptive to considering reducing the 50,000 GJ/day threshold identified in the Dawn Access Settlement as a requirement to allow new receipt points. The threshold volume would still need to be of an amount that would warrant spending

Witnesses: R. DiMaria

D. Small

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monies to upgrade Entrac for a new receipt point. Even with a different threshold, EGD believes that any new receipt point must be of genuine interest from the Direct Purchase customers, at a liquid Hub which would provide alternatives should there be a failure of delivery by the Direct Purchase customer and that EGD must hold renewable transportation capacity from that Hub to the franchise areas.

Witnesses: R. DiMaria D. Small

Exhibit I.D1.EGDI.IGUA.3

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IGUA INTERROGATORY #3

INTERROGATORY

Reference: Exhibit D1, Tab 2, Schedule 3, Page 10

EGD notes that for purposes of the 2018 gas cost forecast, the Company has assumed the amount and value of storage set to expire be extended. The company plans to acquire an additional 2-3 PJs of storage effective April 1, 2018. For gas cost purposes in 2018 the Company has assumed a value for this incremental storage equivalent to the current value of the storage contracts scheduled to expire March 31, 2018. Any variation between the assumed storage costs and the actual cost of storage will be captured in the 2018 S & TDA.

- (a) Please comment on the reasonableness of this assumption.
- (b) What evidence or information does EGD have to demonstrate that this assumption is reasonable?

RESPONSE

a) and b)

In previous Rate Applications, when a storage contract was expected to expire during the forecast period and the gas supply plan dictated the need for said storage to be replaced, absent a new contract to replace it EGD assumed a cost equivalent to the value of the expiring contract(s) for purposes of calculating its forecasted gas cost. This approach has not caused concern in past years.

EGD has yet to send out an RFP for storage capacity for the replacement storage and the incremental 2 to 3 PJ's of storage included in the 2018 Gas Supply Plan, and does not know the value of the storage to be acquired. EGD believes the best approach would be to follow past practice of forecasting the replacement and incremental storage at a cost equivalent to that of the expiring contracts. EGD recognizes that the actual cost of the replacement storage will be different than the forecast cost and therefore it will be necessary to capture any variances in the 2018 Storage & Transportation Deferral Account (2018 S&TDA).

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.3 Page 1 of 1

SEC INTERROGATORY #3

INTERROGATORY

[D1-2-3, p.4]

Please explain how Enbridge will mitigate the impact of the delay in the NEXUS pipeline if it does not go in-service until at least 2019 (i.e. will not be in-serve for the entirety of the 2018 test year).

RESPONSE

The most recent communication that EGD has received indicates that the in-service date of the Nexus pipeline will be September 1, 2017. For a discussion on how EGD plans to mitigate the delay please see response to FRPO Interrogaotry # 5 (Exhibit I.D1.EGDI.FRPO.5)

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.4 Page 1 of 1

SEC INTERROGATORY #4

INTERROGATORY

[D1-2-2]

Please explain how after the merger between Enbridge Inc. and Spectra, Enbridge is leveraging its new affiliate Union, to lower gas supply and transportation costs.

RESPONSE

Included within EGD's 2018 Gas Supply Plan are the cost consequences of contracts entered into between EGD and Union Gas for transmission and storage services that were entered into prior to the acquisition of Spectra by Enbridge Inc. The contractual pricing for storage services was the result of an RFP process and the tolls payable to Union for transmission service is based upon OEB approved tolls.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.5 Page 1 of 1

SEC INTERROGATORY #5

<u>INTERROGATORY</u>

[D1-2-2, p.12]

Please provide a list of storage facilities that are owned by any affiliates of Enbridge, its location, the transmission pipeline it connects to, and its capacity.

RESPONSE

EGD provided a description of storage facilities at Exhibit D1, Tab 2, Schedule 2, page 18 of 27 where it stated:

Enbridge has underground storage (97.8 PJ's) of its own at Enbridge Gas Storage facility near Sarnia in southwestern Ontario and at Crowland near Welland in the Niagara Region. The Enbridge Gas Storage facility is a large multiple-cycle facility, whereas Crowland is a small peak shaving facility. The Company also has contracted capacity with third-party providers (24.4 PJ's) that are valued at market based pricing.

EGD also provided a table at Exhibit D1, Tab 2, Schedule 9, page 2 of 2 listing the various third party contracts that make up the 24.4 PJ's of market based storage. The contracts identified as Contract C, E, F, H, and I are contracts with Union Gas. None of the other third party contracts are with affiliates.

The Enbridge Gas Storage facility interconnects via Company owned transmission lines with the Union Gas facility at Dawn. EGD contracts for transmission capacity on the Union system that allows for the deliver/re-delivery of gas from Dawn to Parkway and then utilizing the TCPL system to transport gas from Parkway to the franchise area.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.6 Page 1 of 1

SEC INTERROGATORY #6

INTERROGATORY

[D1-2-11, p.6-7]

Please confirm that Enbridge opposed at the NEB, in whole or in part, TCPL's proposed Dawn LTFP service approval application. Please explain why, and now that it has been approved, what the impact of the new is Enbridge's gas commodity and transportation costs in the Test Year, and more generally?

RESPONSE

Confirmed, the Company did oppose TCPL's application for the Dawn LTFP service. The Company was concerned with respect to toll subsidization between existing FT Mainline shippers and the impact that the Dawn LTFP service would have on FT service tolls, especially post-2020. The Company also had concerns with the unique tolling methodology that was being proposed for the Dawn LTFP service abandonments costs.

The Company assumes the second part of this interrogatory is with respect to the impact of the Dawn LTFP service. The 2018 Gas Supply plan does not include purchases using the TCPL Dawn LTFP service and therefore it would not impact costs in 2018. However, if during the course the 2018 calendar year an opportunity arose for EGD to acquire a portion of its Dawn requirement through deliveries at Dawn by using the LTFP service then EGD will evaluate the cost impacts at that time. At that time, any variance between the forecasted Dawn price and the equivalent cost using LTFP would be captured in the 2018 PGVA. The Company declines to speculate on the longer term impact of the Dawn LTFP service may or may not have on the Company's commodity and transportation costs due to the uncertainty of the LTFP service cost and the integrated nature of North America's natural gas market.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.7 Page 1 of 1

SEC INTERROGATORY #7

INTERROGATORY

[D1-2-11, p.13]

Please file a copy of the ICF study in this proceeding.

RESPONSE

Please see response to Board Staff Interrogatory #10, at (Exhibit I.D1.EGDI.Staff.10)

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.8 Page 1 of 1 Plus Attachments

SEC INTERROGATORY #8

INTERROGATORY

[D1-2-11, p.13]

Please file a copy of the referenced Direct Purchase market survey.

RESPONSE

Please see a copy of the survey that was sent to approximately 400 customers. Also attached is copy of a spreadsheet summarizing the results of the survey based upon answers received from 23 respondents.



Direct Purchase Receipt Point Survey

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.8 Attachment 1 Page 1 of 1

Q1. Full name
Q2. Organization
Q3. Please tell us your current Supply Arrangement? Ontario Transportation Service (OTS) Western Transportation Service (WTS) OTS & WTS
Q4. Have you elected for Dawn Transportation Service (DTS)? Yes No Other (please specify)
Q5. In addition to Dawn, which other receipt points would be of interest to you? Iroquois Niagara Other
Q6. Please tell us why the receipt point you selected above is of interest to you.
Q7. Please tell us the volume (in GJ) that you would elect for at the new receipt point.
Q8. Please indicate when you would be interested in moving to a new receipt point.
Q9. Please provide us with any comments/feedback regarding Enbridge Transportation Services.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.8 Attachment 2 Page 1 of 1

			3) Bre	3) Breakdown of Moving to	of Moving to New Point (GJ/day)	4) Timing Breakdown of Moving to New Point	akdown of Mc	oving to Ne	w Point		Current service	vice
1) Receipt Point of Interest Respondents	Respondents	2) Total GJ/Day	2018 (20%)	2019 (20%)	No commitment (60%)	2018	2019	2020	Unsure	OTS	WTS C	OTS & WTS
Iroquois	3	8500	1700	1700	5100	1	0	0	2	0	1	2
Iroquois, Niagara	4	2000	400	400	1200	1	0	0	3	1	0	3
Niagara	6	8792	1758	1758	5275	0	2	7	2	9	2	1
Other (Chippawa)	1	N/A	0	0	0	1	0	0	0	1	0	0
Other (Parkway)	1	1000	200	200	009	0	0	0	1	0	0	1
Iroquois, Niagara, Other	1	N/A	0	0	0	0	0	0	1	0	1	0
Other	4	N/A	0	0	0	0	0	0	4	1	2	1
Grand Total	23											

1) Combining the receipt point categories would result in double counting since we gave customers the to option to select more than one point of interest. Responses are kept as they were.

2) Not an accurate figure as many responses failed to indicate a number. Calculated figure is an average of the daily figures actually provided in responses by a few customers. "N/A" and zeros indicate lack of response.

3) Calculated using the Total GJ/day proportioned for the same precentages as the example. Assuming that the move would start in 2018 as per the example.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.SEC.9 Page 1 of 1 Plus Appendix

SEC INTERROGATORY #9

<u>INTERROGATORY</u>

[D1-5-1, p.3]

With respect to the new harmonized non-Union pension plan:

- a. Please provide a copy of the material provided to Enbridge employees explaining the changes in their pension plan.
- b. Please provide a chart showing for all major components of the pension plan, what was included in, i) the previous Enbridge plan, ii) the previous Spectra plan, and iii) the new harmonized plan.
- c. Please provide the revenue requirement impact of the harmonization for the Test Year.

RESPONSE

- a. Attached as Appendix 1 is an excerpt of employee communication materials showing the harmonized pension plan and summarizing major differences between current plans for each company. Please also refer to Tables 1, 2 and 3 in Appendix B (page 11) of the Mercer report (filed at Exhibit D1, Tab 5, Schedule 1) for a description of the changes to the pension plan.
- b. Please refer a) above.
- c. As provided in response to BOMA Interrogatory #29c (Exhibit I.D1.EGDI.BOMA.29), the 2018 accrual based pension and OPEB cost amount would have been forecast \$0.05 million higher (\$20.85 million versus \$20.80 million), while the 2018 forecast cash based amount would have been forecast \$1.40 million higher (\$28.32 million versus \$26.92 million), had the plan harmonization not occurred. Had the higher forecast accrual and cash based amounts been utilized it would have resulted in a decrease of \$0.4 million to the forecast 2018 revenue requirement / Allowed Revenue and gross deficiency amounts. The decrease to the revenue requirement results because the cash based amounts are tax-deductible (so that a higher cash-based amount results in a higher tax benefit).

Witnesses: R. Small

R. Stelmaschuk



Legacy Plans

Pension Overview

- Legacy Enbridge allows for DB or DC choice at hire and again at 40/60 points
- Legacy Spectra allows for a one-time DB or DC choice at hire, which is locked in

Harmonized Plan - DC Start/DB Finish

- New hires join the New DC plan for 5 years, then automatically join the New DB plan
- Transition rules for current employees:



Pension Plan 5 Year DC Start



Different?
- What's [
Enbridge -
Legacy E

4.0% (<40 points) to 9.0% (60+ points)

Harmonized Pension Plan

DC 5%
Contribution
Earnings Base salar

Base salary + 50% Bonus

Legacy Spectra – What's Different?

3.5% (<40 points) to 9.5% (90+

points)

Base salary + 100% bonus

Points = Age + Years of Service

DB Pension Finish (after 5 years)

ENBRIDGE Life Takes Energy."

gacy Enbridge – What's Different?		Harmonized Pension Plan	Legacy Spectra – What's Different?
1.2% or 1.6% less CPP offset, depending on Business Unit	Pension Formula	1.5% x Average Earnings x Credited Service	DB Core: 1.0% DB Buy-up: 2.0%
Previously a temporary bridge	Average Earnings	3 year base salary + 50% best 3 of last 5 bonus	3 year average includes 100% bonus
payable to age 60	Employee Contributions	5% of base earnings, excluding bonus	i.b i.e obi.
Previously non-contributory	Pension Credits by Province	5%: BC, AB, SK, MB, NWT1%: ON, QC, NB, NS	DB Core: none DB Buy-up: 5%
	Net Pension Contribution	None: BC, AB, SK, MB, NWT4%: ON, QC, NB, NS	
50% of CPI	Guaranteed COLA	None (future service only)	Option to purchase COLA with
	Retirement	Lifetime pension for employee and spouseUnreduced at earlier of age	eceived at age 63
	बाल २२	60 or 30 years of service 5%/year reduction	or 85 points Lifetime pension for employee
Same as if leave after age 55	Termination before 55	Lump sum or lifetime pensionUnreduced at 656%/year reduction	SLIDE 3

Exhibit I.D1.EGDI.SEC.10

Page 1 of 1

SEC INTERROGATORY #10

<u>INTERROGATORY</u>

[D1-5-1, App 1, p.2]

Please explain how Mercer incorporated impact of the Ontario Ministry of Finance upcoming pension reforms. Please provide the revenue requirement impact of that proposed change in the 2018.

RESPONSE

EGD's 2018 contributions are required in order to estimate the 2018 forecasted accrual expense. To provide a best estimate of EGD's contributions for 2018, Mercer made assumptions based on the best information available including the most likely filing scenario and anticipated funding reforms. Please refer to BOMA Interrogatory 29(b), at Exhibit I.D1.EGDI.BOMA.29, for a further description of the anticipated reforms. As provided in response to BOMA Interrogatory #29(d), the 2018 accrual based pension and OPEB cost amount would have been forecast \$0.06 million lower (\$20.74 million versus \$20.80 million), while the 2018 forecast cash based amount would have been forecast \$17.68 million higher (\$44.60 million versus \$26.92 million), had the anticipated funding reforms not been reflected. Had the lower forecast accrual and higher cash based amounts been utilized it would have resulted in a decrease of \$6.5 million to the forecast 2018 revenue requirement/Allowed Revenue and gross deficiency amounts. The decrease to the revenue requirement results from a lower accrual based amount included in O&M, and because the cash based amounts are tax-deductible (so that a higher cash-based amount results in a higher tax benefit).

Witness: Mercer

Exhibit I.D1.EGDI.TCPL.1

Page 1 of 2

TCPL INTERROGATORY #1

<u>INTERROGATORY</u>

IR Number: Interrogatory #1

Reference: 1) Exhibit D1, Tab 2, Schedule 9, Page 1 of 2

2) Exhibit D1, Tab 2, Schedule 3, Page 7 of 15

Preamble: In Reference 1, EDGI provides the status of its transportation

contracts for 2018.

In Reference 2, EDGI stated that:

"When the Vector Pipeline recently held an Open Season for capacity for the 2018 winter, the Company evaluated the economics of bidding into the available capacity. However, upon a review of a cost analysis of acquiring incremental Vector capacity versus Dawn purchases the

least cost option was to not bid in for Vector capacity."

Request: a) Please provide a copy of the cost analysis referred to in Reference

2. If that analysis has not been reduced to writing, please do so for

this response.

RESPONSE

Based upon the pricing information available at the time that Vector issued their Open Season, acquiring supplies directly at Dawn would average \$0.07 / GJ lower than acquiring gas in Chicago and using the Vector Pipeline to transport that gas to Dawn.

Below is the cost analysis of the Vector Open Season.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.1 Page 2 of 2

vector Open Season - Summary or Land	eu Cost Analysis (3C/GJ)							
Pipeline	Path	Pricing Point	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Average
Dawn	Dawn Spot Purchases	Dawn	3.69	3.88	3.99	4.00	3.95	3.90
Vector	Chicago-to-Dawn	Chicago	3.65	3.91	4.19	4.19	3.92	3.97
Average Commodity Prices (\$C/GJ)								
Pricing Point			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Average
Chicago			3.40	3.67	3.94	3.94	3.68	3.73
Dawn			3.69	3.88	3.99	4.00	3.95	3.90
Average Foreign Exchange Rate				5 47		5.1.40		
241.04			Nov-17	Dec-17	Jan-18			
C\$/US\$			1.269	1.268	1.268	1.268	1.267	1.268
Average Demand Charge (C\$/GJ)								
Pipeline	Path		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Average
Vector	Chicago-to-Dawn		0.216	0.216	0.216	0.216	0.216	0.216
Average Fuel Ratio								
Pipeline	Path	·	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Average
Vector	Chicago-to-Dawn	·	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%

Exhibit I.D1.EGDI.TCPL.2

Page 1 of 3

TCPL INTERROGATORY #2

<u>INTERROGATORY</u>

IR Number: Interrogatory #2

Reference: 1) Attachment 1: "Enbridge Inc. Reports Third Quarter 2017 Results"

Enbridge.com News Release (excerpt), November 2, 2017, Page 4.2) EB-2015-0166/EB-2016-0175, Decision and Order (December 17,

2015), Page 3, Footnote 8.

Preamble: In Reference 1, Enbridge Inc. states that the "[t]otal capital cost for the

[NEXUS] project has been updated to US\$1.3 billion with an expected

in-service date in the third quarter of 2018."

In Reference 2, the OEB states that "Enbridge's cost estimate reflects the base case for the NEXUS toll, which does not reflect any capital cost overruns related to the greenfield portion of the pipeline. The actual cost for the transportation capacity on NEXUS could be higher or lower, depending on the actual costs to build the NEXUS pipeline."

Request:

- a) Based on EGDI's understanding:
 - i. Please confirm that NEXUS is a 50-50 joint venture, with Enbridge Inc. either directly or indirectly holding a 50% stake in the project. If not confirmed, please describe the joint venture structure, or other structure by which Enbridge Inc. is invested in NEXUS, and in either event include Enbridge Inc.'s share.
 - ii. Please provide Enbridge Inc.'s approximate share of the total estimated capital cost of the NEXUS project at the time of EGDI's application to the OEB for pre-approval of NEXUS costs. If unknown, please provide the total estimated capital cost at the time of EGDI's application for pre-approval with the OEB.
- b) Please confirm that the EGDI-NEXUS Precedent Agreement contains a capital cost tracking adjustment mechanism. If confirmed, please set out and explain the mechanism.
- c) Based on the new capital cost estimate:

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.2

Page 2 of 3

i. Does EGDI expect its NEXUS rate will be set higher than the "base case" noted in Reference 2? If yes, please provide the toll. If no or unknown, please provide EGDI's estimate of the NEXUS transportation toll in light of the new estimated project cost in Reference 1.

ii. Please provide the total incremental impact to ratepayers over the term of EGDI's NEXUS commitment as a result of the change in i).

RESPONSE

- a) In response to a):
 - i. DTE Energy Co. and Spectra Energy Partners, LP are equal partners in the NEXUS pipeline. Spectra Energy Partners, LP became a wholly owned subsidiary of Enbridge Inc. effective February 27, 2017. At the time when EGDI executed its NEXUS contract, Enbridge Inc. was not affiliated with the NEXUS project.
 - ii. At the time when EGDI's application for pre-approval of NEXUS contract costs was before the Board, Enbridge Inc. was not affiliated with the NEXUS project and as a result had no share of the estimated capital costs. The Final Capital Cost Estimate for the NEXUS project was \$2.019 billion US.
- b) Confirmed. EGDI has negotiated a reservation rate of \$0.70 US per Dth for transportation capacity on the NEXUS pipeline. The reservation rate is broken down into a greenfield reservation rate of 0.65 \$US that is subject to a capital cost tracking adjustment mechanism and a 0.05 \$US reservation rate for transportation using existing facilities that is not subject to a capital cost tracker mechanism.

The capital cost tracking adjustment mechanism was established to protect the EGDI ratepayers and the pipeline by limiting the impact of any variances between the estimated and actual project cost on the reservation rate and to incent the pipeline to estimate and manage its project costs in a prudent manner. This is achieved by multiplying the greenfield portion of the reservation rate by the ratio of the actual amount of capital costs and the Final Capital Cost Estimate indicated above up to a threshold of +/-15%. Further details related to the capital cost tracking adjustment mechanism are outlined in the Statement of Negotiated Rates

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.2 Page 3 of 3

which has been filed with the Board as part of EB-20105-0175, Exhibit A, Tab 3, Schedule 1, Appendix G.

c) In response to c):

i. The capital cost discussed in reference 1) has no impact on the reservation rate that EGDI will pay for its NEXUS capacity. The capital cost tracking adjustment mechanism is a function of the Final Capital Cost Estimate which has been established as \$2.019 billion US and the actual project costs which are not known at this time. EGDI declines to speculate on the actual projects costs and as a result cannot speculate on any adjustments to the reservation rate.

In order to be responsive, if the capital cost estimate in reference 1) was assumed to have 100% foresight, then the actual capital cost would be \$2.6 billion (the \$1.3 billion in reference 1) relates to the Spectra Energy Partners, LP share of the total capital cost). In accordance with the capital cost tracking adjustment mechanism, the ratio of actual capital costs and the Final Capital Cost Estimate would be 2.6 / 2.019 = 1.29 (or 29%) which would be capped at 1.15 (or 15%) resulting in an approximate hypothetical adjusted reservation rate of 0.65 * 1.15 + 0.05 = \$0.80 US per Dth.

ii. The impact of \$0.80 US per Dth hypothetical adjusted reservation rate compared to the unadjusted reservation rate would be approximately (0.80 - 0.70) * 110,000 * 365 = \$4.0 million US per year.

Exhibit I.D1.EGDI.TCPL.3

Page 1 of 4 Plus Attachments

TCPL INTERROGATORY #3

<u>INTERROGATORY</u>

IR Number: Interrogatory #3

Reference: 1) Exhibit D1, Tab 2, Schedule 11, Page 2 of 14

2) Attachment 1: "Enbridge Inc. Reports Third Quarter 2017 Results"Enbridge.com News Release (excerpt), November 2, 2017, Page 4

Preamble: In Reference 1, EGDI states that NEXUS' in-service date has been

delayed to 2018.

In Reference 2, Enbridge Inc. states that the "[t]otal capital cost for the [NEXUS] project has been updated to US\$1.3 billion with an expected

in-service date in the third quarter of 2018."

Request: a) Please provide the most recent version of the EGDI-NEXUS

Precedent Agreement. Has the agreement been amended since

December 17, 2015? If so, please provide a summary of the

changes

as well as a blackline version of the updated Precedent Agreement.

- b) Does the Precedent Agreement contain a clause or clauses allowing the Customer (EGDI) to cancel its commitment to NEXUS without liability, including with respect to pre-service costs, should the pipeline be delayed beyond a certain date? If so:
 - i. Please reference the clause(s), state the threshold date(s), and describe any provisions regarding notification to EGDI of such a delay.
- c) Please state whether EGDI agrees with the following statement: Although the OEB has pre-approved the costs associated with the NEXUS pipeline, this pre-approval does not preclude EGDI from acting in the best interests of its ratepayers should it have the opportunity to do so. If EGDI disagrees, please explain.
- d) Should at any point the Phase II NEXUS facilities not be expected to be in-service by the date provided in b), and should EGDI have the ability to terminate the PA without cost liability:

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- i. Will EGDI commit to undertaking a new upstream contracting analysis, including a landed cost analysis, prior to any extension of the estimated commencement date, to determine if more suitable alternatives exist at the time? If not, please explain why not.
- ii. Will EGDI commit to publicly filing any such analysis with the Ontario Energy Board?
- e) Since December 17, 2015, has EGDI had any discussions with NEXUS regarding the provision in b) or regarding the possibility of an in-service date occurring after the date provided in b)? If yes, please provide any correspondence.
- f) Please provide EGDI's Landed Cost Analysis as filed in response to TransCanada information request 1.1(g) in the NEB Dawn Long Term Fixed Price Service proceeding (RH-003-2017)
- g) Please update the Landed Cost Analysis from f) with the expected NEXUS toll changes as provided in TransCanada IR 2 c).

RESPONSE

a) EGD's Restated Precedent Agreement with NEXUS and subsequent amendments are included in I.D1.EGDI.TCPL.3 Attachments 1 through 6. The Restated Precedent Agreement has been amended five times including three amendments since December 17, 2015 which are summarized below.

On May 1, 2017 a third amendment was executed to amend Sections 7(b)(ii) and 7(b)(iv) by extending the date for the pipeline to receive and accept all necessary Governmental Authorizations from May 1, 2017 to June 1, 2017.

On May 31, 2017 a fourth amendment was executed to amend: Section 3(b)(iii) to expand on the Primary Points of Receipt including an election for up to 35,000 Dth per day at TEAL; and Section 7(b)(ii) and 7(b)(iv) to extend the date for the pipeline to receive and accept all necessary Governmental Authorizations from June 1, 2017 to September 1, 2017.

On August 17, 2017 a fifth amendment was executed to amend: Section3(b)(iii) to increase the Maximum Daily Receipt Obligation election at TEAL from 35,000 Dth/d to 55,000 Dth/d and to extend notification period for EGD to elect for receipts at TEAL

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Plus Attachments

from September 1, 2017 to December 1, 2017; Section 6 to insert a provision for the Service Commencement Date that is April 1, 2018 subject to certain conditions; Sections 7(b)(ii) and 7(b)(iv) by extending the date for the pipeline to receive and accept all necessary Governmental Authorizations from September 1, 2017 to December 1, 2017; and lastly to correct a Section reference in the fourth amendment.

- b) EGD expects NEXUS to be service on or prior to November 2018. The ability for EGD to terminate the Restated Precedent Agreement would depend on the circumstances that caused the in-service date of the pipeline to be delayed. The Restated Precedent Agreement includes a number of conditions precedent in Section 7 that must be satisfied otherwise the Agreement will terminate without liability. If the delay referenced in this Interrogatory is with respect to the construction of the pipeline facilities, EGD can terminate the agreement pursuant to Section 10 without liability if Pipeline has not proceeded with due diligence to construct the facilities and commence service. Pursuant to Section 8, EGD would only be liable to pay pre-service costs if the Agreement is terminated due to a material breach by EGD. This is in contrast to the TransCanada form of precedent agreement that imposes pre-service cost liability on shippers in the event of termination of the agreement for delay or prior to service commencement.
- c) EGD's actions demonstrate that it continues to act in the best interests of its ratepayers. As indicated in response to a), the parties have amended the Restated Precedent Agreement in part to extend the period of time for NEXUS to achieve the required Governmental Authorizations. At that time, EGD did re-evaluate the benefits of the NEXUS capacity and found no material changes from what was filed with the Board to support its decision to pre-approve the cost consequences of the NEXUS agreement. The evaluation included a review of the costs; as indicated in response to f) and g), the landed cost of the NEXUS capacity ranks similarly to the landed cost analysis that supported the Board's pre-approval to recover costs for the NEXUS agreement.
- d) Please see responses to parts b) and c) above.
- e) Yes, please see the response to part a) which describes and attaches changes to conditions precedent in the Restated Precedent Agreement that extend the date in which Governmental Authorizations must be achieved by NEXUS.

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- f) Please see Exhibit I.D1.EGDI.TCPL.3 Attachment 7.
- g) Please see Exhibit I.D1.EGDI.TCPL.3 Attachment 8.

Filed: 2017-11-13 EB-2017-0086 Exhibit 1.D1.EGDI.TCPL.3 Attachment 1 Page 1 of 42 EXECUTION VERSION

RESTATED PRECEDENT AGREEMENT

This RESTATED PRECEDENT AGREEMENT ("Restated Precedent Agreement") is made and entered into this I day of December, 2014 ("Effective Date"), by and between DTE Pipeline Company, a Michigan corporation ("DTE"), and Spectra Energy Transmission, LLC, a Delaware limited liability company ("Spectra") (DTE and Spectra are collectively referred to herein as "Pipeline"), and Enbridge Gas Distribution Inc., an Ontario corporation ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties."

WITNESSETH:

WHEREAS, Pipeline is proposing a two-phased project that will ultimately provide approximately one (1) billion cubic feet per day or more of firm transportation service for natural gas production from the Appalachian production areas, including but not limited to the Utica Shale and Marcellus Shale production areas in Ohio and Pennsylvania, to the international border between the United States and Canada near St. Clair, Michigan (the "International Border") and continuing from the International Border to Dawn, Ontario ("Dawn"). In Phase I, Pipeline will provide firm transportation service from Willow Run, Michigan ("Willow Run") to Dawn utilizing subscriptions of firm pipeline capacity on existing pipeline systems ("Phase P"). In Phase II, Pipeline will construct an approximately 250-mile greenfield pipeline extending from points expected to be located at or near Kensington, Ohio to various interconnections in the State of Michigan, utilizing subscriptions of firm pipeline capacity on existing U.S. pipeline systems to transport to the International Border, and thereafter from the International Border to point(s) of delivery in or near Dawn, utilizing one or more of: subscriptions of firm pipeline capacity on

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Exhibit 1.D1.EGDI.TCPL.3

Attachment 1 Page 2 of 42

existing Canadian pipeline systems, an expansion of the existing Vector Canada and/or Union

Canadian pipeline systems, and/or construction of greenfield pipeline facilities ("Phase II") (the

services and subscriptions contemplated herein and the facilities that Pipeline intends to

construct (or use reasonable efforts to cause others to construct) and/or subscribe to provide such

services are collectively referred to herein as the "Project");

WHEREAS, Pipeline is proposing to commence service for the Project in phases, with

Phase I to commence on or about November 1, 2015 and Phase II targeted to commence on or

about November 1, 2017;

WHEREAS Customer, based on its qualifying bid submitted in the Open Season

conducted by Pipeline from October 15, 2012 through November 30, 2012 ("Open Season"),

entered into a Precedent Agreement with Pipeline dated June 5, 2014, as amended on July 31,

2014, (the "Original Precedent Agreement") pursuant to which Pipeline agreed to construct

certain pipeline facilities and to provide the services in respect of Phase I and Phase II to

Customer and Customer agreed to pay for such service(s) in respect of Phase I and Phase II, all

subject to various conditions precedent set forth in the Original Precedent Agreement;

WHEREAS, pursuant to the terms of the Original Precedent Agreement, Customer

notified Pipeline that it did not obtain the approval contemplated in Section 7(c)(i) of the

Original Precedent Agreement, and, as contemplated by Section 9(b) of the Original Precedent

Agreement, the Parties desire to restate the Original Precedent Agreement as further set forth

herein;

WHEREAS, in lieu of the service contemplated under the Original Precedent Agreement,

Customer now desires firm natural gas transportation service in respect of Phase II only from

points expected to be located at or near Kensington, Ohio to the point of interconnection with

-2

Filed: 2017-11-13

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Exhibit 1.D1.EGDI.TCPL.3
Attachment 1

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Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan;

WHEREAS, Pipeline has secured commercial support for the Project evidenced by executed precedent agreements, including this Restated Precedent Agreement with Customer;

WHEREAS, DTE and Spectra contemplate that pipeline companies in the name of NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada have been or will be formed and owned by each of DTE and Spectra or by affiliates of each of them to fulfill the responsibilities of Pipeline hereunder and NEXUS Gas Transmission, LLC and NEXUS Gas Transmission Canada will take assignment of the rights and obligations of and be novated as the Pipeline for all purposes of this Restated Precedent Agreement;

WHEREAS, subject to the terms and conditions of this Restated Precedent Agreement, Pipeline is willing to undertake the steps necessary to provide the Phase II service for Customer described herein and other customers subscribing for capacity as part of the entire Project, to construct the Project facilities or subscribe for firm pipeline capacity that will extend from eastern Ohio to Dawn in order to provide such services, and, if necessary, to construct, or to use reasonable efforts to cause the construction of facilities on existing pipeline systems to provide service on the Project;

WHEREAS, subject to the terms and conditions of this Restated Precedent Agreement, Pipeline is willing to provide the firm transportation service to Customer described herein and Customer is willing to pay Pipeline for such service;

NOW, THEREFORE, in consideration of the mutual covenants herein assumed, and intending to be legally bound, Pipeline and Customer agree as follows:

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1) Pipeline Obligations.

a) Subject to the terms and conditions of this Restated Precedent Agreement, Pipeline shall proceed with due diligence to file applications for and to obtain from all governmental and regulatory authorities having competent jurisdiction over Phase II of the Project, including, but not limited to, the Federal Energy Regulatory Commission ("FERC") and the National Energy Board of Canada ("NEB"), the authorizations, approvals, certificates, permits, notices and/or exemptions (collectively, the "Governmental Authorizations") Pipeline determines are necessary for Pipeline to construct, own, operate, and maintain (and, if necessary, to use reasonable efforts to cause others to construct, own, operate, and maintain) the Project facilities necessary to provide the firm transportation service contemplated for Phase II, including the Phase II service to Customer, commencing on the Phase II Service Commencement Date (as determined in accordance with Section 4 of this Restated Precedent Agreement); and (ii) for Pipeline to otherwise perform its obligations as contemplated in this Restated Precedent Agreement. Pipeline retains full control and discretion in the filing and prosecution of any and all applications for such Governmental Authorizations and/or any supplements or amendments thereto, and, if necessary, any court review, provided it does so in a manner that is consistent with the terms of this Restated Precedent Agreement and designed to implement the firm transportation service contemplated herein in a timely manner. Pipeline agrees to promptly notify Customer in writing when each of the Governmental Authorizations are received, obtained, rejected or denied. Pipeline shall also promptly notify Customer in writing as to whether each of the Governmental Authorizations received or obtained are acceptable to Pipeline.

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b) During the term of this Restated Precedent Agreement, and provided it would be reasonable and prudent for Pipeline to do so, Pipeline agrees to use reasonable efforts to

support and cooperate with the efforts of Customer to obtain all Customer's

Authorizations and supplements and amendments thereto, to better understand and

analyze the markets for the supply of gas at the proposed initial receipt points for Phase II

of the Project and to otherwise perform its obligations as contemplated by this Restated

Precedent Agreement.

c) Pipeline shall, no later than December 19, 2014, provide Customer with confirmation of

the initial receipt points for Phase II transportation service (collectively, the "Initial

Receipt Point Information").

d) The reservation rates payable for transportation service on Phase II (as set forth in the

applicable Pipeline tariffs approved by the FERC and NEB, respectively the "Reservation

Rates") will be set and applied for on a commercially reasonable basis.

2) Customer Obligations.

a) No later than December 19, 2014, Customer will advise Pipeline in writing of: (i) any

facilities which Customer must construct, or cause to be constructed, in order for

Customer to utilize the Phase II service contemplated in this Restated Precedent

Agreement; and (ii) any necessary or desirable contractual and/or governmental or

regulatory authorizations having jurisdiction over the Customer which Customer

determines are necessary or desirable for Customer in order to execute and deliver the

Phase II Service Agreement (as such term is defined in Section 3 below) and to fulfill its

obligations thereunder and to otherwise perform its obligations under this Restated

Precedent Agreement ("Customer's Authorizations").

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b) Subject to the terms and conditions of this Restated Precedent Agreement, Customer shall

proceed with due diligence to obtain the Customer's Authorizations. Customer retains

full control and discretion in the filing and prosecution of any and all applications for

such Customer's Authorizations and/or any supplements or amendments thereto, and, if

necessary, any court review, provided it does so in a manner that is consistent with the

terms of this Restated Precedent Agreement and in a manner designed to implement the

Phase II firm transportation service contemplated herein in a timely manner. Customer

agrees to promptly notify Pipeline in writing when each of the Customer's

Authorizations, are received, obtained, rejected or denied. Customer shall also promptly

notify Pipeline in writing as to whether each of the Customer's Authorizations received

or obtained are acceptable to Customer.

c) During the term of this Restated Precedent Agreement, and provided it would be

reasonable and prudent for Customer to do so, Customer agrees to use reasonable efforts

to support and cooperate with the efforts of Pipeline to obtain all Governmental

Authorizations and supplements and amendments thereto necessary for Pipeline to

provide the Phase II services contemplated hereunder and to construct, own, operate, and

maintain (or, if necessary, to use reasonable efforts to cause others to construct, own,

operate and maintain) the Project facilities for the Phase II services and to otherwise

perform its obligations as contemplated by this Restated Precedent Agreement.

d) As of the Effective Date, Customer agrees that its proposed quantity of firm

transportation service that it wishes to contract for in respect of Phase II as its Maximum

Daily Quantity ("MDQ") for the purpose of the Phase II Service Agreement is 110,000

Dth/d. Customer shall have the right, subject to available capacity, regulatory approvals,

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and the terms of Pipeline's FERC Gas Tariff, to increase its MDQ under the Phase II

Service Agreement up to 150,000 Dth/d. Pipeline will notify Customer whether capacity

is available to satisfy such request to increase Customer's MDQ, taking into

consideration the terms of Pipeline's FERC Gas Tariff. If Pipeline, taking into

consideration the terms of its FERC Gas Tariff, can only accommodate an increase to

Customer's MDQ that is less than requested, Pipeline shall promptly notify Customer of

the amount of the requested increase that can be accommodated, and Customer shall have

ten (10) days from receipt of such notice to either: (i) agree to increase its MDQ to the

amount that can be accommodated; or (ii) retract its request for an increase. If there is to

be an increase to Customer's MDQ pursuant to this Section 2(d), then Pipeline and

Customer shall amend the Phase II Service Agreement to reflect the increase as follows:

i) if Customer requests an increase to its MDQ prior to the Phase II Service

Commencement Date to be effective on the Phase II Service Commencement Date,

and as a result Customer's MDQ is increased to 150,000 Dth/d, then:

(1) the Reservation Rate applicable to Customer's entire MDQ (including any

increase) pursuant to the Phase II Service Agreement and the Phase II Rate

Agreement for the firm transportation service as set forth under Paragraph 3(d)

shall be reduced such that Customer's effective Reservation Rate for service on

the portion of Phase II utilizing newly constructed facilities extending from a

receipt point(s) to be located at or near Kensington, Ohio to an interconnection

point(s) to be located at or near Willow Run, Michigan (the "Greenfield Facilities

- Kensington to Willow Run") is equal to the effective Reservation Rate to be

paid by Union Gas Limited for Phase II service on the Greenfield Facilities -

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Kensington to Willow Run. As of the Effective Date of this Restated Precedent

Agreement, Pipeline estimates that Customer's Reservation Rate would be

reduced by approximately \$0.015 per Dth/d, however, Pipeline and Customer

acknowledge and agree that Pipeline's estimate is non-binding and any change to

Customer's Reservation Rate for purposes of this Section 2(d)(i)(1) will be

determined in accordance with the process outlined for establishing the

reservation rates in Section 3(d); and

(2) Customer shall be entitled to the rights granted under Section 3(e).

ii) If Customer requests an increase to its MDQ after the Phase II Service

Commencement Date or prior to the Phase II Service Commencement Date but to be

effective after the Phase II Service Commencement Date, then:

(1) Customer's request shall be subject to the capacity award mechanism, including

any posting and bidding requirements, set forth in Pipeline's FERC Gas Tariff;

and

(2) if, pursuant to the terms of Pipeline's FERC Gas Tariff, Customer is awarded the

requested capacity and its MDQ is increased to 150,000 Dth/d to be effective

anytime on or before November 1, 2020, then the Reservation Rate applicable to

Customer's entire MDQ (including any increase) pursuant to the Phase II Service

Agreement and the Phase II Rate Agreement for the firm transportation service as

set forth under Paragraph 3(d) shall be reduced, as of the effective date of the

increased MDQ, such that Customer's effective Reservation Rate for service on

the Greenfield Facilities - Kensington to Willow Run is equal to the effective

Reservation Rate paid by Union Gas Limited for Phase II service on the

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Greenfield Facilities – Kensington to Willow Run. As of the Effective Date of this Restated Precedent Agreement, Pipeline estimates that Customer's Reservation Rate would be reduced by approximately \$0.015 per Dth/d as of the

effective date of Customer's increased MDQ, however, Pipeline and Customer

acknowledge and agree that Pipeline's estimate is non-binding and any change to

Customer's Reservation Rate for purposes of this Section 2(d)(ii)(2) will be

determined in accordance with the process outlined for establishing the

reservations rates in Section 3(d).

iii) if Customer's MDQ is increased to an amount that is less than 150,000 Dth/d, the terms of service including Customer's Reservation Rate shall remain unchanged for

all of Customer's MDQ (including any increase).

iv) The terms of this Section 2(d) shall be reflected in the Phase II Rate Agreement and

are subject to applicable regulatory approvals. Except as set forth in this Section 2(d)

or Section 3(e) (if applicable), all other terms of service and rates shall remain

unchanged.

3) Service Agreement.

a) Intentionally left blank.

b) Phase II Firm Service Agreement. To effectuate the firm transportation service

contemplated herein for the Phase II service, Customer and Pipeline agree that (i) no later

than thirty (30) days following the date on which Pipeline provides written notice to

Customer that the FERC, the Michigan Public Service Commission, and any other

governmental agencies or authorities having jurisdiction over the U.S. portion of the

Phase II service have all issued the necessary authorizations to Pipeline or other pipelines

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to construct the greenfield and expansion facilities necessary to provide the U.S. portion of the Phase II service, Pipeline and Customer will execute a firm transportation service agreement governing Customer's service on Phase II as described herein ("Phase II Service Agreement"). The Phase II Service Agreement and the rights and obligations arising thereunder shall only become effective if, in addition to receipt of the aforementioned authorizations for the U.S. portion of the Phase II Service, Pipeline has also provided confirmation that the NEB, Ontario Energy Board ("OEB") and any other governmental agencies or authorities having jurisdiction over the Canadian portion of the Phase II service have all issued the necessary authorizations to Pipeline or other pipelines proposing to construct facilities necessary to provide the Canadian portion of the Phase II For clarity, the Canadian portion of the Phase II service shall have no application to the transportation service that Customer is contracting for, but receipt of the Governmental Authorizations for the Canadian portion of Phase II are a condition precedent to the Phase II Service Agreement between Pipeline and Customer becoming effective as reflected in Section 7(b)(ii). The Parties agree to consider in good faith executing the Phase II Service Agreement at a time earlier than contemplated in the first sentence above if required to allow Pipeline to obtain the requisite notice to proceed with Phase II construction from any governmental agency or authority having jurisdiction. The Phase II Service Agreement will specify the following provisions that will constitute Customer's service on Phase II ("Customer's Phase II Service"): (i) an MDQ of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above), exclusive of fuel requirements, effective on the Phase II Service Commencement Date; (ii) a primary term of fifteen (15) years commencing on the Phase II Service Commencement Date and

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continuing from year to year thereafter unless terminated in accordance with the provisions thereof; (iii) a Primary Point of Receipt (as such term will be defined in the Phase II Service Agreement) at the head of the Phase II facilities in Ohio (such point to be designated by Pipeline at such time as Pipeline provides notice to Customer in accordance with Section 3(c) below) with a Maximum Daily Receipt Obligation ("MDRO") of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above); (iv) a Primary Point of Delivery (as such term will be defined in the Phase II Service Agreement) at the point of interconnection with Vector Pipeline L.P.'s Milford Junction meter station near Highland, Michigan with a Maximum Daily Delivery Obligation ("MDDO") of 110,000 Dth/d (subject to increase in accordance with Section 2(d) above); and (v) security requirements consistent with the provisions set forth in Section 13 below. To the extent Pipeline is authorized to offer access to secondary receipt and delivery points as part of the Phase II service, Customer shall have the right under the Phase II Service Agreement to access secondary receipt and delivery points in accordance with Attached hereto as Exhibit A is an illustrative form of such authorization(s). transportation service agreement for Customer's Phase II Service. . Pipeline provided Customer a copy of the rate agreement and a summary of the general terms and conditions that will be incorporated by reference into the transportation service agreement to form the FERC tariff pursuant to the terms of the Original Precedent Agreement, and Pipeline will provide Customer with any changes to the illustrative form of transportation service agreement in Exhibit A (collectively, the "Forms of Commercial Agreements"). Pipeline will seek Customer's review of the Forms of Commercial Agreements and will consider in good faith any comments provided by Customer.

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Pipeline shall keep Customer informed of any revisions to the Forms of Commercial

Agreements including revisions resulting from comments received from other Customers

in respect of Phase II service. Pipeline shall apply for and seek the Governmental

Authorizations in a manner consistent with the Forms of Commercial Agreements. The

Parties acknowledge and agree that these Forms of Commercial Agreements may change,

as required, as a result of the terms and conditions of approvals from the FERC.

c) Status of Phase II Service Commencement Date. Commencing on January 1, 2015, and

continuing on a quarterly basis thereafter, Pipeline will notify Customer regarding

Pipeline's progress regarding Phase II, and whether the Phase II Service Commencement

Date (as determined in accordance with Section 4 of this Restated Precedent Agreement)

is expected to occur on November 1, 2017, or some later date. No later than November

1, 2015, Pipeline shall in good faith have notified Customer of its bona fide estimate of

the Phase II Service Commencement Date (the "Estimated Phase II Commencement

Date"). In the event that Pipeline's bona fide estimate of the Estimated Phase II

Commencement Date is a date that is after November 1, 2018, then, unless such

deadline(s) are extended by mutual consent, Customer shall have no further obligation in

respect of contracting for Customer's Phase II Service and Customer shall have the right

to terminate this Restated Precedent Agreement in respect of Customer's Phase II Service

without liability between the Parties including in respect of the Customer being required

to pay any Pre-Service Costs.

d) Rates.

i) Intentionally left blank.

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ii) The rates that will apply to the Phase II Service Agreement shall be as set forth in the rate agreement to be executed in accordance with this Section 3(d), for service under the Phase II Service Agreement. Pipeline and Customer have agreed to the following with regard to the rates for service under the Phase II Service Agreement:

- (1) Subject to the terms and conditions set forth herein and in the Phase II Service Agreement and in the Phase II Rate Agreement (as defined below), upon execution of such service and rate agreements, Customer shall be obligated to pay Pipeline the rates specified for service under the Phase II Service Agreement commencing on the Phase II Service Commencement Date and continuing to the end of the primary term (as set forth in the Phase II Service Agreement) thereof.
- (2) Pipeline and Customer acknowledge that the scope of the facilities necessary for Pipeline to provide Customer's Phase II Service and for all other customers subscribing for Phase II service (such facilities are collectively referred to herein as the "Phase II Facilities") is not known with precision at this time. For this reason, the estimated capital costs associated with construction of the Phase II Facilities and the estimated Reservation Rates and fuel rates for Customer's Phase II Service under the Phase II Service Agreement will be set forth in the Phase II Rate Agreement provided in accordance with Section 3(d)(ii)(3) below. Pipeline currently estimates that the Reservation Rate for Customer's Phase II Service under the Phase II Service Agreement will be \$0.70 US per Dth/d (the "Estimated Phase II Rate"), plus the applicable U.S. fuel rate, with such fuel rate in the range of 1.6% 2.6%. The Estimated Phase II Rate may be adjusted as more fully set forth in Section 3(d)(ii)(3) and subject to the terms of Section 3(d)(ii)(4) below.

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(3) No later than December 19, 2014 Pipeline shall provide Customer with a draft estimate of the capital costs associated with construction of the New Phase II Facilities (as defined below), the revised Reservation Rate (the "Revised Phase II Rate") applicable to Customer's Phase II Service, subject to a fifteen percent (+/-15%) capital cost tracking adjustment (as more particularly described in Exhibit C (the "Capital Cost Tracking Adjustment") around the revised estimate, and the revised fuel rate estimate, to be set forth in the rate agreement for the Phase II Service Agreement. The capital cost estimate will be provided substantially in the same form as an Exhibit K - Cost of Facilities (as defined in the Federal Energy Regulatory Commission's Code of Federal Regulations) for the New Phase II Facilities. At such time as Pipeline provides Customer with the Revised Phase II Rate, Pipeline will provide information which sets forth a more detailed breakdown of how the Pipeline has derived such Revised Phase II Rate ("Rate Breakdown"), including a breakdown of such portion of the Reservation Rate for Customer's Phase II Service that is derived from the capital costs associated with the construction of the New Phase II Facilities for Customer's Phase II Service. No later than January 16, 2015, Pipeline shall deliver to Customer a final estimate of capital costs for the New Phase II Facilities, final Reservation Rate for Customer's Phase II Service (subject to the Capital Cost Tracking Adjustment) (the "Final Reservation Rate") and final estimated fuel rate to be set forth in the rate agreement for the Phase II Service Agreement and any final revisions to the Rate Breakdown as well as the final rate agreement for the Phase II Service Agreement (the "Phase II Rate Agreement"). Pipeline and Customer shall

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promptly execute the Phase II Rate Agreement; provided that, if the Final

Reservation Rate set forth in the Phase II Rate Agreement is higher than the

Estimated Phase II Rate set forth in Section 3(d)(ii)(2) above, and such higher

Reservation Rate has caused the value of the commercial transaction with respect

to the natural gas to be transported under the Phase II Service Agreement to be

uneconomical to Customer, as determined by Customer in its sole and absolute

discretion, Customer shall not be obligated to execute the Phase II Rate

Agreement.

(4) In the event that Customer has elected not to execute the Phase II Rate Agreement

in accordance with the proviso in the last sentence of Section 3(d)(ii)(3), Pipeline

and Customer shall promptly meet and work in good faith in an attempt to agree

upon Reservation Rate that are commercially acceptable to both Parties, each

Party in its sole discretion. If, after thirty (30) days, the Parties are unable to

agree upon a mutually acceptable Reservation Rate, either Party shall have the

right to terminate this Restated Precedent Agreement and, if executed, the Phase

II Service Agreement. Any termination of this Restated Precedent Agreement

pursuant to this Section will be without liability to either Party including in

respect of the Customer being required to pay any Pre-Service Costs.

e) Most Favored Nations. The following provisions of this Section 3(e) shall only apply and

become effective should the Customer make an election in accordance with Section

2(d)(i) to increase its MDQ to 150,000 Dth/day effective as of the Phase II Service

Commencement Date and the entire amount requested to be increased can be

accommodated by Pipeline.

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i) Except as provided in Section 3(e)(ii) below, in the event that Pipeline enters into or

has entered into firm transportation service and/or recourse, negotiated or discount

rate agreements with other similarly situated customers (as to transportation path,

quantity and length of term) in respect of Phase II containing any rate provisions and

other terms of service that are more favorable to such other customers than the

negotiated rate provisions set forth in the Phase II Rate Agreement, Pipeline shall

offer Customer, within ten (10) business days of entering into the rate agreements (or

to the extent such rate agreements existed prior to the exercise by Customer of the

right in Section 2(e)), then within ten (10) business days of confirmation that

Customer's MDQ has been increased to 150,000 Dth/d), those same rate provisions

and other terms of service. If Customer is willing to accept the offer on the exact

same terms and conditions as such other customer(s), including provisions regarding

transportation path, volume and length of term, then Customer will so notify Pipeline

within thirty (30) days of its acceptance, and Pipeline will make the necessary

amendments to the Phase II Rate Agreement and the Phase II Service Agreement, as

applicable, and the Parties will enter into amended agreements at the more favorable

rate for the remainder of the term of the applicable agreement(s). This section will

apply only to contracts Pipeline enters into for service utilizing Project capacity on or

before the Phase II Service Commencement Date.

ii) Exclusions. Pipeline is not required to offer to Customer and Customer is not entitled

to, any rate provisions provided to other customers if such rate provisions are

contained in long-term firm service agreements for capacity that becomes available as

a result of the breach, default or unauthorized termination of a precedent agreement or

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associated service agreement by a Project customer or the bankruptcy, insolvency,

liquidation or other similar action affecting a Project customer. In addition, the most

favored nation right set forth in this Section 3(e) will not be available to Customer in

respect of any short term (i.e., less than one year) service. Further, the most favored

nation right set forth in this section 3 will not apply to credit provisions.

(f) Right of First Refusal. Customer will, in respect of the Phase II Service Agreement be

granted a contractual Right of First Refusal ("ROFR") in accordance with the Pipeline

tariff approved by the FERC. Further, the Phase II Service Agreement will be considered

a ROFR Agreement in accordance with, and as that term is used in, Pipeline's FERC

tariff.

4) Commencement of Service.

(a) Intentionally left blank.

(b) Phase II. With respect to Phase II transportation service, Pipeline shall provide at least

ninety (90) days' prior notice (the "In-Service Date Notice") to Customer of the projected

service commencement date for service under the Phase II Service Agreement, which

date shall be the beginning of a calendar month and cannot be earlier than the date upon

which Pipeline has satisfied or waived all the conditions precedent, provided that the

actual service commencement date for purposes of the Phase II Service Agreement (the

"Phase II Service Commencement Date") shall be the date that is the later of: (i)

November 1, 2017; (ii) the date provided in the In-Service Date Notice; (iii) the date that

is the first day of the first calendar month following the date on which the Pipeline places

the Phase II Facilities into service; or (iv) if, pursuant to Section 7(f), the Pipcline has

filed an appeal or is pursuing a rehearing, reconsideration or clarification by the

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applicable regulatory authority of the Governmental Authorization, then 90 days from the

date of receipt of a positive decision addressing Customer's concerns unless such period

is waived by Customer. On and after the Phase II Service Commencement Date, Pipeline

shall provide firm transportation service for Customer pursuant to the terms of the Phase

II Service Agreement and Customer will pay Pipeline for all applicable charges required

by the Phase II Service Agreement and the Phase II Rate Agreement.

5) Design and Permitting of Project Facilities. Pipeline will undertake with due diligence, or

use reasonable efforts to cause others to undertake, the design of the Phase II Facilities and

any other preparatory actions necessary for Pipeline, or Pipeline's designee(s), to complete

and file application(s) related to the Phase II Facilities with the FERC, NEB and/or other

governmental authorities as appropriate. Prior to satisfaction of the conditions precedent set

forth in Section 7(b)(i) through 7(b)(vii) of this Restated Precedent Agreement, Pipeline, or

Pipeline's designee(s), shall have the right, but not the obligation, to proceed with the

necessary design of facilities, acquisition of materials, supplies, properties, rights-of-way and

any other necessary preparations to implement the firm transportation service under the

Phase II Service Agreement as contemplated in this Restated Precedent Agreement.

Additionally, Pipeline will use commercially reasonable efforts to keep Customer informed

on a regular basis and respond to any of Customer's requests for information concerning

Phase II schedule changes, status of Governmental Authorizations, service commencement

dates, and/or changes to any of the rates described herein.

6) Construction of Project. Upon satisfaction of the conditions precedent set forth in Sections

7(b)(i) through 7(b)(vii), inclusive and 7(c) of this Restated Precedent Agreement, or waiver

of the same by Pipeline or Customer, as applicable, Pipeline shall proceed with due diligence

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to construct, or to use reasonable efforts to cause others to construct, the authorized Phase II

Facilities and to implement the firm transportation service contemplated in this Restated

Precedent Agreement for Customer's Phase II Service on or about November 1, 2017, or

such later date as may be designated by Pipeline in accordance with Section 3(c) above. If,

notwithstanding Pipeline's due diligence, Pipeline, or Pipeline's designee(s), is unable to

commence the Phase II service for Customer on November 1, 2017, or such later date as may

be designated by Pipeline in accordance with Section 3(c) above, Pipeline will continue to

proceed with due diligence to complete arrangements for such firm transportation service,

and commence such service for Customer at the earliest practicable date thereafter. Subject

to Section 9(a), Pipeline will neither be liable nor will this Restated Precedent Agreement or

the Phase II Service Agreement be subject to cancellation if Pipeline, or Pipeline's

designee(s), is unable to complete the construction of such authorized Project facilities and

commence the Phase II service for Customer by November 1, 2017 or such later date as may

be designated by Pipeline in accordance with Section 3(c) above.

7) Conditions Precedent. Commencement of service under the Phase II Service Agreement and

Pipeline's and Customer's rights and obligations thereunder are expressly made subject to

satisfaction or waiver, as applicable, of the following conditions precedent in Sections 7(b)

and 7(c), provided that only Pipeline shall have the right to waive the conditions precedent

set forth in Section 7(b) and only Customer shall have the right to waive the conditions

precedent set forth in Section 7(c):

a) Intentionally left blank.

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b) Pipeline's Conditions Precedent for Phase II Service.

i) Pipeline filing by April 1, 2015 the necessary requests with the FERC and/or NEB for

approval to provide Phase II service as contemplated herein and in the Phase II

Service Agreement;

ii) Subject to Section 7(d), Pipeline's receipt and acceptance in accordance with Section

7(f) by May 1, 2017, of all necessary Governmental Authorizations to construct, own,

operate and maintain the Phase II Facilities (including FERC, NEB, and OEB

authorizations, as applicable), all as described in Pipeline's applications as they may

be amended from time to time, necessary to provide the Phase II service, including

Customer's Phase II Service contemplated herein and in the Phase II Service

Agreement;

iii) Pipeline (or Pipeline's owners or their respective affiliates) having received on or

before May 1, 2017, a binding commitment from a financial institution(s) to provide

the necessary financing of the construction of the Phase II Facilities;

iv) Other pipelines having received and accepted in accordance with Section 7(f) by May

1. 2017, all necessary Governmental Authorizations to construct, own, operate and

maintain the Phase II Facilities, all as described in their applications as they may be

amended from time to time, necessary to provide the Phase II service including

Customer's Phase II Service contemplated herein and in the Phase II Service

Agreement;

v) Pipeline receiving approval, no later than thirty (30) days after its acceptance of the

certificates and authorizations specified in Section 7(b)(i), from its Management

Committee, or similar governing body, to expend the capital necessary to construct

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the Phase II Facilities and to proceed with the Phase II-related firm pipeline transportation arrangements with other pipelines for service on the Phase II Facilities;

- vi) Pipeline's receipt no later than four (4) months prior to the Phase II Service Commencement Date of all necessary authorizations required to construct the Phase II Facilities necessary to provide the Phase II firm transportation service including Customer's Phase II Service contemplated herein and in the Phase II Service Agreement, other than those specified in Section 7(b)(ii);
- vii)Pipeline's procurement, no later than four (4) months prior to the Phase II Service

 Commencement Date, of all rights-of-way, easements or permits (in form and substance acceptable to Pipeline, acting reasonably) necessary for the construction and operation of the Phase II Facilities;
- viii) Pipeline's completion of construction of the Phase II Facilities and all other facilities required to render Customer's Phase II Service pursuant to the Phase II Service Agreement and for other customers subscribing for Phase II service and Pipeline being ready, able and authorized to place such facilities into gas service; and
- ix) The completion of the construction of the facilities necessary to create the pipeline capacity subscribed to Pipeline as part of Phase II of the Project by other pipelines, as applicable, and each such Party being ready, able and authorized to place such facilities into service.
- c) Customer's Conditions Precedent.
 - i) Intentionally left blank.

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- ii) Customer's acceptance, no later than 30 days following receipt of Initial Receipt Point Information in accordance with Section 1(c), of the initial receipt points proposed by the Pipeline for Phase II transportation service;
- iii) Customer's confirmation to Pipeline, no later than 90 days following receipt of the Estimated Phase II Commencement Date, that it has completed its review and approval of regional supply necessary to support natural gas supply arrangements associated with Customer's service under the Phase II Service Agreement, respectively; and
- iv) If, pursuant Section 3(d)(ii), the Final Reservation Rate exceeds the Estimated Reservation Rate, then Customer's receipt, no later than 60 days following receipt of the requisite internal corporate approvals of such Final Reservation Rate for Phase II;
- v) Customer's receipt and acceptance of the approvals from the OEB for its application related to the Customer's Phase II Service no later than October 1, 2015; and
- vi) Subject to Section 7(d), Customer's receipt and acceptance no later than 30 days following satisfaction of the condition in Section 7(c)(iii), of any necessary Customer Authorizations identified in accordance with Section 2(a) of this Restated Precedent Agreement.
- d) Temporary Waiver of Conditions Precedent Governmental Authorizations.

 Notwithstanding Sections 7(b)(ii), 7(b)(iv), 7(c)(iii) and 7(c)(iv) and subject to Section 24, either Party may, in its sole discretion, temporarily waive satisfaction of its conditions precedent listed above for a period of 90 days. During such a delay, upon reasonable request by the other Party, the Party waiving its condition precedent shall use commercially reasonable efforts to provide timely notices to the other Party in writing

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regarding the filing of any applications for such Governmental Authorizations or

Customer Authorization, as the context requires, and will provide periodic updates

regarding the status of such applications, including notice when each of the

authorizations are received, obtained, rejected or denied. The Party temporarily waiving

it condition precedent shall also promptly notify the other Party in writing as to whether

each of the Governmental Authorizations or Customer Authorizations, as the context

requires, received or obtained are acceptable to such Party. If the Party temporarily

waiving its condition precedent has not satisfied the conditions precedent associated with

the receipt of all Governmental Authorizations or Customer Authorizations, as the

context requires, within ninety (90) days' time, either Party may terminate this Restated

Precedent Agreement on thirty (30) days' written notice and no Pre-Service Costs will be

payable by Customer.

e) With respect to each condition precedent set forth in Section 7(b) of this Restated

Precedent Agreement, with the exception of the conditions precedent set forth in clauses

(vii) and (viii) of Section 7(b), Pipeline shall provide notice to Customer within five (5)

days of the satisfaction of such condition precedent that the condition precedent has been

satisfied. With respect to each condition precedent set forth in Section 7(c) of this

Restated Precedent Agreement, Customer shall provide notice to Pipeline within five (5)

days of the satisfaction of each such condition precedent that the condition precedent has

been satisfied.

f) Unless otherwise provided for herein, the Governmental Authorization(s) contemplated

in Section 1 of this Restated Precedent Agreement must be issued in form and substance

satisfactory to both Parties, acting reasonably. For purposes of this Restated Precedent

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Agreement, such Governmental Authorization(s) shall be deemed satisfactory if issued or granted with terms and conditions which are: (i) consistent with this Restated Precedent Agreement and all ancillary agreements and documents to be delivered pursuant to this Restated Precedent Agreement for the applicable service; and (ii) to the extent not contemplated by this Restated Precedent Agreement or any of the ancillary agreements and documents, not materially onerous on Pipeline, as determined by Pipeline, acting reasonably, and will not otherwise have a material adverse effect on Customer. Customer shall notify Pipeline in writing not later than fifteen (15) days after Pipeline notifies Customer of the issuance of the FERC and/or NEB certificate(s), authorization(s) and approval(s), including any order issued as a preliminary determination on nonenvironmental issues, contemplated in Section 1 of this Restated Precedent Agreement if Customer determines, acting reasonably, that such certificate(s), authorization(s) and approval(s) will have a material adverse effect on Customer. Customer cannot assert that any authorization will have a material adverse effect on Customer unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Pipeline in its application, unless the provisions requested by Pipeline were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). All other Governmental Authorizations that Pipeline must obtain must be issued in form and substance acceptable

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to Pipeline, acting reasonably. All Governmental Authorizations that Pipeline is required by this Restated Precedent Agreement to obtain must be duly granted by the FERC, NEB, or other governmental agency or authority having jurisdiction, and must be final and no longer subject to rehearing or appeal; provided, however, Pipeline may waive the requirement that such Governmental Authorizations be final and no longer subject to rehearing or appeal. If any of the Governmental Authorizations are issued on material terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(f), then the non-accepting Party, acting reasonably, shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to Phase II. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement and Phase Il Rate agreement. Any termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs. Notwithstanding the foregoing, if the Parties cannot agree on a modification or alternate provision, Pipeline may, in its sole discretion, appeal or otherwise pursue rehearing, reconsideration or clarification by the applicable regulatory authority of any such provision(s) which Customer alleges will have a material adverse effect on it, and Customer may not terminate this Restated Precedent Agreement until a final order or decision is rendered by such regulatory authority which does not grant relief that is satisfactory to Customer, acting reasonably, to address such material adverse effect, or

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180 days from the date that Pipeline makes its application for rehearing, reconsideration or clarification, whichever occurs first.

g) The Customer Authorization(s) contemplated in Section 2 of this Restated Precedent Agreement shall be deemed satisfactory if issued or granted in form and substance substantially as requested, or if issued in a manner acceptable to Customer and such Customer Authorization(s), as issued, will not otherwise have a material adverse effect on Pipeline. Pipeline cannot assert that any authorization will have a material adverse effect on Pipeline unless: (i) the governing provisions of such authorization differ materially and adversely from the provisions requested by Customer in its application, unless the provisions requested by Customer were inconsistent with the terms of this Restated Precedent Agreement; and (ii) such differences materially and adversely affect the rate to be charged pursuant to the rate agreement contemplated herein, or the terms and conditions of service pursuant to the service agreement contemplated herein, and the Parties cannot mutually agree upon a modification or alternative to such provision which preserves the relative economic positions of the Parties under the operative agreement(s). If any of the Customer Authorizations are issued on terms not acceptable to either Party, subject to the foregoing provisions of this Section 7(g), then the non-accepting Party shall give notice to the other Party, and the Parties shall promptly meet and work in good faith in an attempt to agree upon a commercially acceptable resolution for both Parties, each Party in its sole discretion, to continue forward with respect to Phase II. If, after thirty (30) days, the Parties are unable to agree upon a mutually acceptable resolution, either Party shall have the right to terminate this Restated Precedent Agreement and, if executed, the Phase II Service Agreement and Phase II Rate Agreement.

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termination of this Restated Precedent Agreement by a Party pursuant to this Section will be without liability between the Parties including in respect of the Customer being required to pay any Pre-Service Costs.

- h) In the event the Estimated Phase II Commencement Date is changed to a date later than November 1, 2017 in accordance with Section 3(c), the Parties agree that each of the dates in Sections 3(d)(ii), 7(b)(i) through 7(b)(iii), Sections 7(c)(ii) through 7(c)(iv), and Section 10 will be changed to a later date by the same amount of time as such change to the Estimated Phase II Commencement Date.
- Pre-Service Costs. If Customer is in material breach of any of its obligations arising pursuant to this Restated Precedent Agreement and such material breach is not cured within 30 days of notice to Customer by Pipeline of such breach, or if such breach is not capable of being cured within 30 days, and Customer is not continuing thereafter in good faith and with diligence to cure such breach, and, as a result thereof, the Phase II Service Commencement Date does not occur, then Customer shall, at the option and election of Pipeline, reimburse Pipeline within thirty (30) days of Pipeline's invoice, for its pro-rata share, based on Customer's MDQ for Phase II service to total contracted MDQ for Phase II service by all customers with executed Restated Precedent Agreements, for the Pre-Service Costs incurred or otherwise committed to by Pipeline up to the date of the occurrence of the material breach which resulted in the Phase II Service Commencement Date to not occur. In no event shall Customer's exposure to Pre-Service Costs exceed \$163 million U.S. dollars if Customer's MDQ for Phase II service is 110,000 Dth/d, or \$219 million U.S. dollars if Customer's MDQ for Phase II service is 150,000 Dth/d. Customer's liability for its share of the Pre-Service Costs in accordance with this Section 8 constitutes a genuine pre-estimation of Pipeline's

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liquidated damages and not as a penalty, and the payment by Customer of such amount, if such payment is required to be made in accordance with this Section 8 shall constitute Pipeline's sole remedy in such instance, with no right to claim further damages or other remedies from Customer. If this Restated Precedent Agreement is terminated for any reason other than a material breach by Customer, then such termination shall be without any liability on the part of Customer to Pipeline, including in respect of the Customer being required to pay any Pre-Service Costs. The term, "Pre-Service Costs" for all purposes in this Restated Precedent Agreement means only those expenditures and/or costs reasonably and prudently incurred, accrued, allocated to, or for which Pipeline is contractually obligated to pay in furtherance of Pipeline's efforts to develop and construct Phase II of the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on Phase II of the Project facilities, including such expenditures associated with design, testing, engineering, construction, commissioning, materials and equipment, environmental, regulatory, and/or legal activities, allowance for funds used during construction, negative salvage, internal overhead and administration and any other costs reasonably incurred in furtherance of Pipeline's efforts to develop and construct Phase II of the Project and to satisfy its obligations under this Restated Precedent Agreement and all other precedent agreements for service on Phase II of the Project facilities. In the event Customer incurs liability for Pre-Service Costs, Pipeline shall use commercially reasonable efforts to mitigate the amount of Pre-Service Costs. NOTWITHSTANDING THE FOREGOING, THE PARTIES HERETO AGREE THAT NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR ANY PUNITIVE, SPECIAL, EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES (INCLUDING,

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WITHOUT LIMITATION, LOSS OF PROFITS OR FOR BUSINESS INTERRUPTIONS)
ARISING OUT OF OR IN ANY MANNER RELATED TO THIS PRECEDENT
AGREEMENT, AND WITHOUT REGARD TO THE CAUSE OR CAUSES THEREOF
OR THE SOLE, CONCURRENT OR CONTRIBUTORY NEGLIGENCE (WHETHER
ACTIVE OR PASSIVE), STRICT LIABILITY (INCLUDING, WITHOUT LIMITATION,
STRICT STATUTORY LIABILITY AND STRICT LIABILITY IN TORT) OR OTHER
FAULT OF EITHER PARTY. THE IMMEDIATELY PRECEDING SENTENCE
SPECIFICALLY PROTECTS EACH PARTY AGAINST SUCH PUNITIVE,
EXEMPLARY, INDIRECT, INCIDENTAL OR CONSEQUENTIAL DAMAGES EVEN IF
WITH RESPECT TO THE NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL
MISCONDUCT, STRICT LIABILITY OR OTHER FAULT OR RESPONSIBILITY OF
SUCH PARTY; AND ALL RIGHTS TO RECOVER SUCH DAMAGES OR PROFITS
ARE HEREBY WAIVED AND RELEASED.

9) Termination of Restated Precedent Agreement for Failure of Conditions Precedent.

a) If the conditions precedent set forth in Section 7 of this Restated Precedent Agreement have not been fully satisfied or waived by Pipeline or Customer, as applicable, by the earlier of the applicable dates specified therein or within one year after the Estimated Phase II Commencement Date, and this Restated Precedent Agreement has not otherwise been terminated pursuant to the other terms of this Restated Precedent Agreement, including in respect of Sections 10 or 11 hereof, then this Restated Precedent Agreement (and any Phase II Service Agreement) shall terminate effective 30 days after the date such condition precedent was to be satisfied or waived by the applicable Party and such termination shall be without liability including in respect of Customer being required to

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pay any Pre-Service Costs, except to the extent the failure is as a result of a breach by a Party of its other obligations set forth in this Restated Precedent Agreement.

- b) For any termination in accordance with Section 9(a) above, the Parties agree to promptly meet and work diligently and in good faith for a period of 30 days following the date such condition precedent was to be satisfied or waived to attempt to agree upon changes to this Restated Precedent Agreement that would allow the Restated Precedent Agreement to continue, which may include a waiver of and/or change in the deadline for any of the conditions precedent that are the subject of such termination notice, provided that if the Parties are unable to come to an agreement upon changes that would allow the Restated Precedent Agreement to continue, then this Restated Precedent Agreement (and the Phase II Service Agreement) shall nonetheless terminate effective on the expiry of such 30 day period.
- c) Any delay or failure in the performance by either Party hereunder shall be excused if and to the extent caused by the occurrence of a Force Majeure. Notwithstanding the foregoing, if any condition precedent set forth in Section 7 hereof has not been satisfied as a result of an occurrence of Force Majeure, the deadline for satisfying the condition precedent shall be extended for each day that the occurrence of Force Majeure continues up to a maximum of ninety (90) days or as mutually agreed to by the Parties. For purposes of this Restated Precedent Agreement, "Force Majeure" as employed herein shall mean any cause, whether of the kind enumerated herein or otherwise, not within the reasonable control of the Party claiming suspension, and which by the exercise of due diligence, such Party has been unable to prevent or overcome, including without limitations acts of God, the government, or a public enemy; strikes, lockouts, or other

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industrial disturbances; wars, terrorism, blockades, or civil disturbances of any kind; epidemics, landslides, hurricanes, washouts, tornadoes, storms, fires, explosions, arrests, and restraints of governments or people, freezing of, breakage or accident to, or the necessity for making repairs to machinery or lines of pipe; and the inability of either the claiming Party to acquire, or the delays on the part of either of the claiming Party in acquiring, at reasonable cost and after the exercise of reasonable diligence: (a) any servitudes, rights of way, grants, permits or licenses; (b) any materials or supplies for the construction or maintenance of facilities; or (c) any Governmental Authorizations, permits or permissions form any governmental agency; if such are required to enable the claiming Party to fulfill its obligations hereunder.

10) Termination for Default. The occurrence and continuation of a material breach by a Party of any of its obligations under this Restated Precedent Agreement, unless caused by a breach by the other Party of its obligations under this Restated Precedent Agreement is referred to herein as a "Default". Upon the occurrence of a Default by a Party hereto, the non-defaulting Party may provide written notice to the defaulting Party, describing the Default in reasonable detail and requiring the defaulting Party to remedy the Default (the "Default Notice"). If the Default is not cured within 30 days of receipt by the defaulting Party of the Default Notice, or if such breach is not capable of being cured within 30 days, and the defaulting Party is not continuing thereafter in good faith and with diligence to cure such Default, the non-defaulting Party may, by termination notice to the defaulting Party, terminate this Restated Precedent Agreement effective on the tenth (10th) day following receipt of the termination notice by the defaulting Party; provided, however, that if during such ten (10) day period the defaulting Party has commenced to remedy the Default and is continuing in good faith its

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efforts to remedy such Default, the entitlement of the non-defaulting Party to terminate this

Restated Precedent Agreement will be suspended until the earlier of the cessation by the

defaulting Party of such efforts and the date which is ninety (90) days after the date of the

Default Notice.

11) Other Pipeline Termination Rights. In addition to the provisions of Section 9 hereof,

Pipeline may terminate this Restated Precedent Agreement at any time upon fifteen (15)

days' prior written notice to Customer, if: (i) Pipeline, in its sole and reasonable discretion,

determines for any reason on or before October 1, 2016, that the Project contemplated herein

is no longer economically viable, (ii) Pipeline incurs or will incur costs which are twenty-five

percent (25%) or more than the cost estimate submitted as part of Pipeline's application to

the FERC for the certificate of public convenience and necessity for the Project related to the

Project construction, or (iii) on or before October 1, 2016, substantially all of the other

precedent agreements, service agreements or other contractual arrangements for the firm

transportation service to be made available by the Project are terminated, other than by

reason of commencement of service. In the event Pipeline terminates this Restated Precedent

Agreement in accordance with this Section 10, Customer shall not be liable pursuant to

Section 8 above for Pre-Service Costs.

12) Termination Upon Service Commencement Date; Survival. If this Restated Precedent

Agreement is not terminated pursuant to Sections 9, 10 or 11 hereof, or otherwise in

accordance with the terms of this Restated Precedent Agreement, then, except for those

provisions herein that are stated to survive any termination of this Restated Precedent

Agreement, this Restated Precedent Agreement will terminate by its express terms on the

Phase II Service Commencement Date and thereafter Pipeline's and Customer's rights and

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obligations related to the transportation service contemplated herein shall be determined

pursuant to the terms and conditions of the Phase II Service Agreement and Phase II Rate

Agreement, as applicable, and Pipeline's FERC gas tariff, as effective from time to time.

Notwithstanding any termination of this Restated Precedent Agreement, each Party shall

remain liable to the other Party for all losses or damages suffered, sustained or incurred by

the other Party as a result of a breach of any obligations of a Party which breach arose prior

to termination of this Restated Precedent Agreement, provided that Customer's liability shall

only apply if and to the extent it is to be liable in accordance with Section 8 and, such

liability, if any, shall not exceed its share of Pre-Service Costs determined in accordance with

Section 8. Notwithstanding any termination of this Restated Precedent Agreement pursuant

to terms of this Restated Precedent Agreement, to the extent that a provision of this Restated

Precedent Agreement contemplates that one or both Parties may have further rights and/or

obligations hereunder following such termination, the provision shall survive such

termination as necessary to give full effect to such rights and/or obligations.

13) Creditworthiness. At all times during the effectiveness of this Restated Precedent Agreement

and the related Service Agreement(s), Customer, pursuant to the criteria and terms set forth

in this Section 13, shall either maintain a Creditworthy status, as defined below, or furnish

sufficient credit support to Pipeline.

a) Creditworthiness Standard. Customer shall at all times during the effectiveness of this

Restated Precedent Agreement and the Service Agreement(s) be Creditworthy or provide

the Guaranty or the Letter of Credit contemplated herein. For purposes herein,

"Creditworthy" means, in respect of the applicable entity, such entity has and maintains:

(i) a long-term senior unsecured debt rating from (a) Moody's Investors Service, Inc.

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("Moody's") of Baa3 or higher, and (b) Standard & Poor's ("S&P") of BBB- or higher

and, with respect to each rating, not on negative credit watch or outlook, and (ii) a

sufficient open line of credit as of the Effective Date. Pipeline acknowledges and agrees

that, as of the effective date of this Restated Precedent Agreement, Customer has a

sufficient open line of credit with Pipeline and Customer shall not at any time hereafter

be required to establish any line of credit in connection with this Restated Precedent

Agreement. If Customer is rated by only one of the foregoing credit rating agencies,

Customer shall be creditworthy if it has the rating described in the foregoing sentence

from the agency by which it is rated. If Customer is rated by both of the rating agencies

described above but one such agency's rating is lower than the other agency's rating, then

Customer's creditworthiness shall be determined based on the lower of the Moody's or

S&P rating. Alternatively, Customer may be accepted as Creditworthy by Pipeline if

Pipeline determines that, notwithstanding the absence of the rating requirements in this

Section 13(a), the financial position of Customer (or an entity that guarantees all of

Customer's payment obligations) is and remains acceptable to Pipeline during the term of

the Restated Precedent Agreement and the Phase II Service Agreement.

b) Failure to Meet Creditworthiness Standard. In the event Customer fails at any time or

from time to time during the term of this Restated Precedent Agreement or the applicable

service agreements to meet the Creditworthy standard set forth in Section 13(a)

(including if its Guarantor, if applicable is no longer Creditworthy), Customer shall

provide credit support to Pipeline in the form of one of the following methods set forth in

this Section 13(b):

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i) Guaranty. Customer will provide, or cause to be provided, a guaranty (a "Guaranty") from Customer's parent company or from an affiliate (a "Guarantor"), provided the Guaranty shall serve to satisfy Customer's obligations under this Section 13 only if such Guarantor is Creditworthy, and only for so long as the Guarantor remains Creditworthy and for so long as it guarantees Customer's payment obligations and the Guaranty otherwise satisfies the requirements of this clause (i). The Guaranty shall: (a) guarantee all payment obligations of Customer under this Restated Precedent Agreement and the Phase II Service Agreement, (b) remain in effect until all payment obligations under this Restated Precedent Agreement and the Phase II Service Agreement have been satisfied in full, and (c) be in a form and content substantially similar to Exhibit D hereto. Pipeline may require, at any time and from time to time, Customer to provide, or cause to be provided, an additional guaranty from a Creditworthy guarantor if the original Guarantor is, at any time, no longer Creditworthy. If Customer becomes Creditworthy after providing a Guaranty, Customer may request a discharge and return of such Guaranty, and following such request Pipeline shall promptly provide such discharge and return.

Letter of Credit. If, at any time and from time to time, during the effectiveness of this Restated Precedent Agreement and/or the Phase II Service Agreement Customer fails to meet the requirements of Sections 13(a) and 13(b)(i) above, Customer shall provide, or cause to be provided, at its sole cost, a standby irrevocable letter of credit (a "Letter of Credit") from a Qualified Institution. For purposes herein, a "Qualified Institution" shall mean a major U.S. or Canadian commercial bank, or the U.S. branch offices of a foreign bank, which is not the Customer or Customer's Guarantor (or a

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subsidiary or affiliate of the Customer or Customer's Guarantor) and which has assets of at least \$10 billion dollars and a credit rating of at least "A-" by S&P, or "A3" by Moody's. Pipeline may require Customer at Customer's cost to substitute a Qualified Institution if the Letter of Credit provided is, at any time, from a financial institution which is no longer a Qualified Institution. The Letter of Credit shall: (i) remain in effect until all payment obligations under this Restated Precedent Agreement and the Phase II Service Agreement have been satisfied in full, (ii) be in a form acceptable to Pipeline, which for purposes herein shall mean in form and content substantially similar to Exhibit E hereto, and (iii) be in the amount equal to twenty-four (24) months of reservation rates based on the MDQ and reservation rates under the Phase II Service Agreement. If Customer becomes Creditworthy after providing a Letter of Credit, Customer may request a discharge and return of such Letter of Credit, and following such request Pipeline shall promptly provide such discharge and return.

- c) <u>Demand for Assurances</u>. At any time and from time to time, Pipeline shall have the right to require that Customer demonstrate Customer's, or its Guarantor's, continuing satisfaction of the creditworthiness and credit support requirements in this Section 13. Customer will have a period of five (5) business days to make such demonstration or to furnish credit support acceptable to Pipeline in accordance with this Section 13.
- d) Failure to Comply. The failure of Customer to timely satisfy or maintain the requirements set forth in this Section 13 shall in no way relieve Customer of its other obligations under this Restated Precedent Agreement or the Phase II Service Agreement, nor shall it affect Pipeline's right to seek damages or performance under this Restated Precedent Agreement or the Phase II Service Agreement. Further, if, prior to the Phase II

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Service Commencement Date, Customer fails to timely satisfy or maintain the requirements set forth in this Section 13, then Pipeline may give written notice to Customer of such failure, and, if such failure is has not been cured within five (5) business days following the receipt by Customer of such notice, then Pipeline may elect

business days following the feeeigh by Customer of such holice, then I iponite may elect

to suspend or terminate performance under this Restated Precedent Agreement, or to

terminate this Restated Precedent Agreement and, if applicable, the Phase II Service

Agreement.

e) Term of Credit Provisions and Survival. This Section 13 shall survive the termination of

this Restated Precedent Agreement and shall remain in effect until all payment

obligations under this Restated Precedent Agreement and the Phase II Service

Agreement, if applicable, have been satisfied in full.

f) Replacement Customer Creditworthiness. In the event Customer assigns this Restated

Precedent Agreement or the Phase II Service Agreement in accordance with the

applicable assignment provision(s), or in the event Customer permanently releases all or

a portion of Customer's capacity under the Phase II Service Agreement in accordance

with Pipeline's FERC Gas tariff and/or NEB Gas tariff, then the assignee and/or the

permanent replacement customer, as applicable, shall be required to satisfy the

requirements of this Section 13 with respect to all such assigned or replacement

agreements, and upon satisfaction of the requirements of this Section 13, Pipeline shall

return to Customer any Guaranty or Letter of Credit which had been furnished by

Customer pursuant to this Section 13.

14) Amendments. This Restated Precedent Agreement may not be modified or amended unless

the Parties execute written agreements to that effect.

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15) Successors; Assignments. Any company which succeeds by purchase, merger, or

consolidation of title to all or substantially all of the assets of a Party will be entitled to the

rights and will be subject to the obligations of such Party in title under this Restated

Precedent Agreement, and in such respect, no consent to such an assignment shall be

required from the other Party. In addition, this Restated Precedent Agreement is assignable

in whole or in part without the prior written consent of the Customer: (a) by Pipeline or either

DTE or Spectra to either or both of: (i) NEXUS Gas Transmission, LLC; and (ii) NEXUS

Gas Transmission Canada; (b) by Pipeline to any joint venture or similar collaborative entity

created between DTE and Spectra, provided such entity is created for the sole purpose of

advancing the Project (it being understood that it is the intention of DTE and Spectra to

establish pipeline companies in the name of NEXUS Gas Transmission, LLC and NEXUS

Gas Transmission Canada, or another joint venture or similar collaborative, to advance the

Project); or (c) between DTE and Spectra, in respect of each Party's interests in the Project.

Otherwise, neither Customer nor Pipeline may assign any of its rights or obligations under

this Restated Precedent Agreement without the prior written consent of the other Party

hereto, such consent not to be unreasonably withheld. Notwithstanding the foregoing,

Pipeline shall have the right, without obtaining Customer's consent, to pledge or assign its

rights under this Restated Precedent Agreement, the Phase II Service Agreement or the Phase

II Rate Agreement as collateral security for indebtedness incurred by Pipeline (or by an

affiliate of Pipeline) for the Project.

16) No Third-Party Rights. Except as expressly provided for in this Restated Precedent

Agreement, nothing herein expressed or implied is intended or shall be construed to confer

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upon or give to any person not a Party hereto any rights, remedies or obligations under or by

reason of this Restated Precedent Agreement.

17) Joint Efforts: No Presumptions. Each and every provision of this Restated Precedent

Agreement shall be considered as prepared through the joint efforts of the Parties and shall

not be construed against either Party as a result of the preparation or drafting thereof. It is

expressly agreed that no consideration shall be given or presumption made on the basis of

who drafted this Restated Precedent Agreement or any specific provision hereof.

18) Recitals and Representations. The recitals and representations appearing first above are

hereby incorporated in and made a part of this Restated Precedent Agreement.

19) Choice of Law. This Restated Precedent Agreement shall be governed by, construed,

interpreted, and performed in accordance with the laws of the State of Ohio, without recourse

to any laws governing the conflict of laws.

20) Notices. Except as herein otherwise provided, any notice, request, demand, statement, or bill

provided for in this Restated Precedent Agreement, or any notice which either Party desires

to give to the other, must be in writing and will be considered duly delivered when mailed by

registered or certified mail or overnight courier or when provided by personal delivery or

electronic mail to the other Party's address set forth below:

Pipeline: Vice President, Business Development

5400 Westheimer Court

Houston, TX 77056

brmckerlie@spectraenergy.com

Phone - (713) 627-4582

Fax - (713) 627-4727

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Customer: Director, Energy Supply and Policy

500 Consumers Road North York, Ontario

M1K 5E3

Jamie.LeBlanc@enbridge.com

Phone - (416) 495-5241

Fax - (416) 495-6072

or at such other address as either Party designates by written notice. Routine

communications, including monthly statements, will be considered duly delivered when

mailed by registered mail, certified mail, ordinary mail, or overnight courier or when

provided by electronic mail to the person and at the addresses noted above or as otherwise

designated pursuant to this Section 20.

21) Waivers. The waiver by either Party of a breach or violation of any provision of this

Restated Precedent Agreement will not operate as or be construed to be a waiver of any

subsequent breach or violation hereof.

22) Counterparts. This Restated Precedent Agreement may be executed in any number of

counterparts, each of which will be an original, but such counterparts together will constitute

one and the same instrument.

23) Headings. The headings contained in this Restated Precedent Agreement are for reference

purposes only and shall not affect the meaning or interpretation of this Restated Precedent

Agreement.

24) Governmental Authorizations. Notwithstanding any provision to the contrary, each provision

of this Restated Precedent Agreement shall be subject to all applicable laws, statutes,

ordinances, regulations, rules, court decisions and Governmental Authorizations.

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25) Definitions. Capitalized terms used herein have the meanings ascribed to them in the body of

this Restated Precedent Agreement, and for the purposes of reference only are listed in

Exhibit F attached hereto.

[signature page follows]

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IN WITNESS WHEREOF, the Parties hereto have caused this Restated Precedent Agreement to be duly executed by their duly authorized officers as of the day and year first above written.

DTE PIPELINE COMPANY	ENBRIDGE GAS DISTRIBUTION, INC.
By:	By: Cargant
Title: PCESI dent	Title: Glenn Beaumont President
SPECTRA ENERGY TRANSMISSION, LLC	0256 b 8

US/Transmissun and Strage

APPROVED AS WORM

James Lord Vice President Law & Information Technology Filed: 2015-06-05, EB-2015-0175, Exhibit A, Tab 3, Schedule 1, Appendix E, Page 1 of 8

EXECUTION VERSION

Filed: 2017-11-13 EB-2017-0086

Exhibit I.D1.EGDI.TCPL.3 Attachment 2

FIRST AMENDMENT TO RESTATED PRECEDENT AGREEMENT

This First Amendment ("Amendment") to the Restated Precedent Agreement dated December 17, 2014 between Enbridge Gas Distribution Inc., an Ontario corporation, (hereafter referred to as "Customer"), and Spectra Energy Transmission, LLC, a Delaware limited liability company ("Spectra") and DTE Pipeline Company, a Michigan corporation ("DTE") (Spectra and DTE are collectively referred to herein as "Pipeline") is effective June 3, 2015. Customer and Pipeline are sometimes referred to herein as a "Party" or collectively as the "Parties." Capitalized terms used but not defined herein have the meanings given to them in the PA (as the same is defined below).

WHEREAS, the Parties entered into that certain Restated Precedent Agreement ("PA") dated December 17, 2014 for the purpose of setting forth the terms and conditions according to which Customer would commit to, and Pipeline would provide to Customer, firm transportation service on the Project; and

WHEREAS, the Parties wish to amend the PA to reflect the terms and conditions for service on the Project to be provided by Pipeline to Customer.

NOW THEREFORE for good and valuable consideration, the receipt of which is acknowledged by all Parties hereto as sufficient and received, the Parties herby agree that the PA shall be amended as follows, effective as of the date indicated above:

- 1. The phase "Phase II" and all references thereto shall be deleted in each place where it is found in the PA. For these purposes, the term "Project" or the term "transportation" shall be substituted where the context may require to maintain the continuity and meaning of the statement; otherwise, the term shall simply be deleted.
- 2. The references to the "NEB" in the following sections shall be deleted: Section 1(d); Section 5; Section 7(b)(i); and Section 7(f).
- 3. The first WHEREAS clause is amended by the following: deleting the phrase "two-phased" in the first line; adding the words "up to" after the word "provide" in the first line; striking the words "one (1) billion" and replacing them with "one and one half (1.5) billion"; striking the words "or more" in the second line; and, in the seventh, eighth and ninth lines, deleting the words from "In Phase I" through "In Phase II,".
- 4. The second WHEREAS clause is amended by deleting the words "in phases, with Phase I to commence on or about November 1, 2015 and Phase II targeted to commence".
- 5. The third WHEREAS clause is amended by deleting the phase beginning with "pursuant to which" and through the end of the clause.
- 6. Section 3(b) is amended by inserting the following at the end of the third to last sentence: "provided that, for clarity, the Rate Agreement shall not be revised by Pipeline other than for the sole purpose of conforming the terms of the same with the terms of the NEXUS FERC Gas Tariff (when approved by FERC) and, to the extent not materially adverse to Customer within the context of its participation as a shipper in the Project, with the terms agreed to in rate agreements of other anchor shippers for the Project."

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.3 Attachment 2 Page 2 of 8

7. Section 3(d)(ii)(2) is deleted in its entirety and replaced with the following:

The estimated Reservation Rates and fuel rates for service under the Service Agreement shall be set forth in the Rate Agreement provided in accordance with Section 3(d)(ii)(3) below. The estimated capital costs associated with the construction of the facilities necessary for Pipeline to provide Project service for Customer and all other customers subscribing Project service in the U.S. (the "Project Facilities") will be reflected in an estimate to be provided by Pipeline to Customer in accordance with Section 3(d)(ii)(3) below.

8. Section 3(d)(ii)(3) is deleted in its entirety and replaced with the following:

Contemporaneously with the execution of the First Amendment to this Restated Precedent Agreement, Pipeline shall deliver to Customer the following: (a) the final rate agreement for the Service Agreement (the "Rate Agreement"), which shall include the final estimate of the Reservation Rate (the "Final Estimated Reservation Rate") (subject only to the Capital Cost Tracking Adjustment, as defined below) and estimated fuel rate; (b) a final breakdown of how Pipeline derived the Final Estimated Reservation Rate, including a breakdown of such portion of the Final Estimated Reservation Rate that is derived from the Final Capital Cost Estimate (as defined below) ("Rate Breakdown"); and (c) an estimate of the capital costs associated with the construction of the Project Facilities ("Final Capital Cost Estimate"). The Rate Agreement shall provide, consistent with Exhibit C, that the Final Estimated Reservation Rate shall be subject to an aggregate fifteen percent (+ / - 15%) capital cost tracking adjustment (as more particularly described in Exhibit C, the "Capital Cost Tracking Adjustment"). Pipeline and Customer shall hereafter execute the Rate Agreement as expeditiously as is practicable.

9. Section 3(d)(ii)(4) is deleted in its entirety.

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- 10. Section 7(b)(i) is amended by replacing "2015" with "2016" in the first line.
- 11. Section 7(c)(ii) is deleted in its entirety and replaced with "Intentionally left blank".
- 12. Section 7(c)(iv) is deleted in its entirety and replaced with "Intentionally left blank".
- 13. Section 7(c)(v) is amended by adding the words "Subject to Section 7(d)" at the beginning of the section.
- 14. Add a new Section 7(c)(vii) stating as follows: "Subject to the other terms of this Restated Precedent Agreement, Customer acknowledges that it has received, prior to the Effective Date, the requisite internal corporate approvals for the performance of Customer's obligations under this Restated Precedent Agreement and other agreements related to the service contemplated hereunder."

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- 16. Section 8 is amended by adding the word "material" added after "its' in the first line, and by adding the following after the sentence ending "or other remedies from Customer." and prior to the sentence beginning "If this Restated Precedent Agreement is terminated":

Pipeline represents that no work to be conducted in relation to Pre-Service Costs will be conducted in Canada. In the event that Pipeline issues to Customer an invoice in relation to Pre-Service Costs work conducted in Canada, Pipeline shall separate the invoice between work performed in Canada and outside of Canada, identify on the invoice the number of days performing work in Canada (including travel days to/from Canada) and the physical location, indicating city and province, where the Canadian work was performed. Customer shall request from Pipeline the relevant documentation necessary to determine the appropriate withholding amount, if any, for tax purposes. In the event that taxes are withheld from the Pre-Service Costs paid by Customer, then Customer shall remit such withheld taxes to the applicable taxing authority and the Customer will provide to Pipeline, after the applicable calendar year end, Pipeline's U.S. Federal Form 1099, a comparable state form or Canadian Revenue Authority equivalent, if applicable, within the applicable statutory time frame. In the event that Customer is assessed for any non-resident withholding taxes payable, Pipeline agrees to forthwith reimburse Customer for such amount together with applicable interest and penalties, if any."

- 17. Section 9(a) is amended by adding the word "direct" before the word "result" in the last sentence, and by adding the word "material" prior to the word "breach" in the last sentence.
- 18. Section 9(c) is amended by adding the following, beginning prior to the period at the end of the first sentence, and ending prior to the words "Notwithstanding the foregoing,":
 - , provided that such Party claiming Force Majeure shall give written notice of the suspension of such performance for this reason as soon as reasonably possible to the other Party and stating the date and extent of such suspension and the cause thereof. The Party whose obligations have been suspended as aforesaid shall resume the performance of such obligations as soon as reasonably possible after the removal of the cause and shall so notify, in writing, the other Party that the suspension has terminated.
- 19. Add a new Section 26, as follows: "Entire Agreement. This Restated Precedent Agreement and the other agreements contemplated herein to be executed and delivered by the Parties embody the complete agreement and understanding among the Parties with respect to the subject matter hereof and supersede and pre-empt any prior understandings, agreements (including, without limitation, the Original Precedent Agreement) or representations by or among the Parties, written or oral, which may have related to the subject matter hereof in any way."
- 20. Exhibit C is deleted in its entirety and replaced with the language set forth on Exhibit 1 to this Amendment.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.3 Attachment 2

Page 4 of 8

21. Exhibit F is amended as follows:

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a. Delete the following defined terms: (i) "Class III Estimate"; (ii) "Estimated Phase II Rate"; (iii) "New Phase II Facilities"; (iv) "Phase II"; (v) "Phase II"; (vi) "Revised Phase II Rate".

- b. In respect of the defined term "Final Reservation Rate" add the words "Estimated" between "Final" and "Reservation Rate";
- c. Add the following defined term: "Exhibit K" has the meaning ascribed to that term in the FERC regulations in Title 18 of the Code of Federal Regulations;
- d. Add the following defined term: "Final Reservation Rate" has the meaning ascribed to that term in Exhibit C;
- e. Add the following defined term: "Final Capital Cost" has the meaning ascribed to that term in Exhibit C;
- f. Add the following defined term: "Final Capital Cost Estimate" has the meaning ascribed to that term in Section 3(d)(ii)(3);
- g. Add the following defined term: "Project Facilities Rate Portion" has the meaning ascribed to that term in Exhibit C;
- h. Add the following defined term: "Updated Capital Cost" has the meaning ascribed to such term in Exhibit C.
- i. Add the following defined term: "Updated Reservation Rate" has the meaning ascribed to that term in Exhibit C;

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

Filed: 2015-06-05, EB-2015-0175, Exhibit A, Tab 3, Schedule 1, Appendix E, Page 5 of 8

EXECUTION VERSION Filed: 2017-11-13

EB-2017-0086

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IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives Attachment 2 to execute this Amendment, effective as of the date first above written. Page 5 of 8

ENBRIDGE GAS DISTRIBUTION INC.:
BY: (Original Signed)
NAME: Malini Giridhar
TITLE: Vice President, Gas Supply & Business <u>Development</u>
BY: (Original Signed)
NAME: Glen Beaumont
TITLE: President
SPECTRA ENERGY TRANSMISSION, LLC
SPECTRA ENERGY TRANSMISSION, LLC BY: (Original Signed)
,
BY: (Original Signed)
BY: (Original Signed) NAME: William T. Yardley
BY: (Original Signed) NAME: William T. Yardley
BY: (Original Signed) NAME: William T. Yardley TITLE: President
BY: (Original Signed) NAME: William T. Yardley TITLE: President DTE PIPELINE COMPANY

EXECUTION VERSION Filed: 2017-11-13

EB-2017-0086

Exhibit I.D1.EGDI.TCPL.3 Attachment 2 Page 6 of 8

Exhibit 1

REPLACEMENT EXHIBIT C TO RESTATED PRECEDENT AGREEMENT

Capital Cost Tracking Adjustment for Statement of Negotiated Rates

Project Facilities

Pipeline and Customer acknowledge that the capital costs attributable to the Project Facilities, which capital costs will underlie a portion of the Reservation Rate for firm transportation service for the Project, will be reflected in the Final Capital Cost Estimate to be provided to Customer by Pipeline in accordance with Sections 3(d)(ii)(2) and 3(d)(ii)(3).

Negotiated Reservation Rate Adjustment

The Final Estimated Reservation Rate will be adjusted, pursuant to the provisions set forth herein, to reflect any differences between the Final Capital Cost Estimate and the actual amount of capital costs attributable to the Project Facilities.

Pipeline will adjust the portion of the Final Estimated Reservation Rate attributable to the Project Facilities as set forth in the final Rate Breakdown (the "Project Facilities Rate Portion") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date. The adjustment to the Project Facilities Rate Portion will be based on a comparison between the Final Capital Cost Estimate and an updated cost report prepared by Pipeline and provided to Customer which updates the estimate of the capital costs for the Project Facilities, substantially in the form of an Exhibit K (the "Updated Capital Cost"). Pipeline will file such Updated Capital Cost report with the Federal Energy Regulatory Commission ("Commission") at least thirty (30) days, but not more than sixty (60) days, prior to the Service Commencement Date.

In making the adjustment described above, Pipeline will adjust the Project Facilities Rate Portion to reflect the percentage increase or decrease between the Updated Capital Cost and the Final Capital Cost Estimate. In the event that the Updated Capital Cost exceeds the Final Capital Cost Estimate, the Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted upward by multiplying it to the ratio of the Updated Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other provision contained herein, if the Updated Capital Cost exceeds the Final Capital Cost Estimate by more than 15%, then the multiplier to the Project Facilities Rate Portion will be 1.15. For the avoidance of doubt, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). In the event that the Updated Capital Cost is less than the Final Capital Cost Estimate, the Project Facilities Rate Portion of the Final Estimated Reservation Rate will be adjusted downward by multiplying it to the ratio of the Updated

Page 7 of 8

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Capital Cost to the Final Capital Cost Estimate; provided that, notwithstanding any other Attachment 2 provision contained herein, if the Updated Capital Cost is less than the Final Capital Cost Estimate by more than 15%, then the multiplier to the Project Facilities Rate Portion will be .85. For the avoidance of doubt, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). The reservation rate resulting from the adjustment provided for in this paragraph shall be the "Updated Reservation Rate".

Pipeline will make a final adjustment to the Project Facilities Rate Portion no later than 210 days after the Service Commencement Date. In making the final adjustment, Pipeline shall prepare and provide to Customer a final cost report which sets forth the actual capital costs for the Project Facilities, substantially in the form of an Exhibit K ("Final Capital Cost"). In the event the Final Capital Cost exceeds the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum upward adjustment to the Project Facilities Rate Portion shall be capped at 1.15 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). In the event the Final Capital Cost is less than the Updated Capital Cost, then the Project Facilities Rate Portion of the Updated Reservation Rate will be adjusted by multiplying the Project Facilities Rate Portion of the Final Estimated Reservation Rate to the ratio of the Final Capital Cost to the Final Capital Cost Estimate; provided that, in any event, the maximum downward adjustment to the Project Facilities Rate Portion shall be capped at .85 of what was set forth in the Rate Breakdown for the Project Facilities Rate Portion provided by Pipeline pursuant to Section 3(d)(ii)(3). The reservation rate resulting from the adjustment provided for in this paragraph shall be the "Final Reservation Rate".

In the event that the adjusted Reservation Rate decreases because the Final Capital Cost is less than the Updated Capital Cost, Pipeline will refund Customer an amount (including interest at the Commission's approved interest rate pursuant to 18 C.F.R. §154.501, hereafter the "FERC Interest Rate") equal to the difference between the revenue received from Customer for the time period that Customer paid the Updated Reservation Rate and the revenue that Pipeline would receive for such time period had Customer paid the Final Reservation Rate. In the event that the adjusted Reservation Rate increases because the Final Capital Cost is more than the Updated Capital Cost, Customer will pay Pipeline an amount (including interest at the FERC Interest Rate) equal to the difference between the revenue received from Customer for the time period that Customer paid the Updated Reservation Rate and the revenue that Pipeline would have received for the time period had Customer paid the Final Reservation Rate.

Recourse Reservation Rate Adjustment

In the case of an upward adjustment to the Final Estimated Reservation Rate, Pipeline will file the Updated Capital Cost report, together with an adjusted recourse rate

Page 8 of 8

applicable to transportation service for the Project, with the Commission at least thirty Attachment? (30) days, but no more than sixty (60) days, prior to the Service Commencement Date. In the case of a downward adjustment to the Final Estimated Reservation Rate, Pipeline has the right, but not any obligation, to prepare and file such Updated Capital Cost report and/or an adjustment to the recourse rate applicable to transportation service for the Project with the Commission.

Cost Reports

Pipeline will prepare the Updated Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline's reasonable good faith estimate at the time of the total capital costs attributable to Project Facilities as constructed. Pipeline will prepare the Final Capital Cost report in accordance with Section 157.14(a)(13) of Title 18 of the Code of Federal Regulations. Such report will reflect Pipeline's actual capital costs attributable to the Project Facilities as constructed.

Filed: 2017-11-13

EB-2017-0086

SECOND AMENDMENT TO RESTATED PRECEDENT AGREEMENT Attachment 2

Page 1 of 2

This Second Amendment ("Amendment") to the Restated Precedent Agreement dated December 17, 2014 and amended as of June 3, 2015 between Enbridge Gas Distribution Inc., an Ontario corporation, (hereafter referred to as "Customer"), and NEXUS Gas Transmission, LLC (successor to Spectra Energy Transmission, LLC and DTE Pipeline Company) ("Pipeline"), is effective January 28, 2016. Customer and Pipeline are sometimes referred to herein as a "Party" or collectively as the "Parties." Capitalized terms used but not defined herein have the meanings given to them in the PA (as the same is defined below).

WHEREAS, the Parties entered into that certain Restated Precedent Agreement ("PA") dated December 17, 2014 and amended as of June 3, 2015 for the purpose of setting forth the terms and conditions according to which Customer would commit to, and Pipeline would provide to Customer, firm transportation service on the Project; and

WHEREAS, the Parties wish to amend the PA as provided herein.

NOW THEREFORE for good and valuable consideration, the receipt of which is acknowledged by all Parties hereto as sufficient and received, the Parties herby agree that the PA shall be amended as follows, effective as of the date indicated above:

1. Section 7(c)(iii) is amended by deleting the phrase "90 days following receipt of the Estimated Commencement Date", and replacing it with the phrase "February 12, 2016".

[Signature Page Follows]

Exhibit I.D1.EGDI.TCPL.3

Attachment 3

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Amendment, effective as of the date first above written.

Page 2 of 2

ENBRIDGE GAS DISTRIBUTION INC.:
BY: Malin Grahe
NAME: Maiini Giridhai Vice President
TITLE:
BY:
NAME: Glenn Beaumont
TITLE:
NEXUS GAS TRANSMISSION, LLC By: Spectra Energy NEXUS Management, LLC in its capacity as operator:
BY: Del
NAME: Brian Riyckerlie
TITLE: U. P.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.3 Attachment 4 Page 1 of 2

THIRD AMENDMENT TO RESTATED PRECEDENT AGREEMENT

This Third Amendment to Restated Precedent Agreement (this "Amendment") is made and entered into as of May 1, 2017 between NEXUS Gas Transmission, LLC, (successor in interest to DTE Pipeline Company and Spectra Energy Transmission, LLC) ("Pipeline"), and Enbridge Gas Distribution Inc. ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties". Capitalized terms used but not otherwise defined herein have the meanings given to them in the Precedent Agreement, as defined below.

RECITALS

WHEREAS, the Parties entered into that certain Restated Precedent Agreement dated December 17, 2014 and amended as of June 3, 2015 and January 28, 2016 (the "Precedent Agreement"), for the purpose of setting forth the terms according to which Customer would commit to, and Pipeline would provide to Customer, firm natural gas transportation service on the Project; and

WHEREAS, the Parties wish to amend the Precedent Agreement with respect to certain conditions precedent.

NOW, THEREFORE, for good and valuable consideration, the receipt of which is hereby acknowledged by the Parties as sufficient and received, the Parties hereby agree that the Precedent Agreement shall be amended as follows, effective as of the date indicated above, with the Precedent Agreement remaining otherwise in full force and effect in accordance with its terms:

- 1. Section 7(b)(ii) is amended by deleting the phrase "May 1, 2017" in the second line thereof and replacing it with the phrase "June 1, 2017".
- 2. Section 7(a)(iv) is amended by deleting the phrase "May 1, 2017" in the first and second lines thereof and replacing it with the phrase "June 1, 2017".

[Signature Page Follows]

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.3 Attachment 4

Page 2 of 2

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Amendment as of the date first written above.

NEXUS Gas Transmission, LLC

By: Spectra Energy NEXUS Management,

LLC, in its capacity as operator

Name: Brian 12 McKerlie
Title: U.P

Enbridge Gas Distribution Inc.

By: Vice President,
Title: Title:

By: Jim Sanders
Title:

Exhibit I.D1.EGDI.TCPL.3

Attachment 5 Page 1 of 3

FOURTH AMENDMENT TO RESTATED PRECEDENT AGREEMENT

This Fourth Amendment to Restated Precedent Agreement (this "Amendment") is made and entered into as of May 31, 2017 between NEXUS Gas Transmission, LLC, (successor in interest to DTE Pipeline Company and Spectra Energy Transmission, LLC) ("Pipeline"), and Enbridge Gas Distribution Inc. ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties". Capitalized terms used but not otherwise defined herein have the meanings given to them in the Precedent Agreement, as defined below.

RECITALS

WHEREAS, the Parties entered into that certain Restated Precedent Agreement dated December 17, 2014 (as the same has been amended, the "Precedent Agreement"), for the purpose of setting forth the terms according to which Customer would commit to, and Pipeline would provide to Customer, firm natural gas transportation service on the Project; and

WHEREAS, the Parties wish to amend the Precedent Agreement as set forth herein.

NOW, THEREFORE, for good and valuable consideration, the receipt of which is hereby acknowledged by the Parties as sufficient and received, the Parties hereby agree that the Precedent Agreement shall be amended as follows, effective as of the date indicated above, with the Precedent Agreement remaining otherwise in full force and effect in accordance with its terms:

1. Section 3(b)(iii) is amended by deleting the text beginning with the phrase "a Primary Point of Receipt" and continuing through the phrase "(subject to increase in accordance with Section 2(d) above)", and replacing it with the following, between "(iii)" and the semicolon that precedes "(iv)": "Primary Points of Receipt (as such term is defined in the Service Agreement or Pipeline's FERC Gas Tariff, as applicable) as follows: (A) at Pipeline's meter #N2002-NEXUS/KENSINGTON MR02 at the Kensington Processing Plant in Kensington. Ohio, with a Maximum Daily Receipt Obligation ("MDRO") of 110,000 Dth; (B) at Pipeline's meter #N4994-MARKET ZONE 1 CUSTODY TRANSFER POINT (the accounting point at Kensington, Ohio), as further described in the Service Agreement and in Pipeline's FERC Gas Tariff, with an MDRO of 110,000 Dth; and, subject to written notice from Customer to Pipeline no later than September 1, 2017 and subject to the availability of Capacity on the Project at the time of such written notice, (C) at Pipeline's meter #N4995-NEXUS INTERCONNECT WITH TETLP, MONROE CO., OH, near Clarington, OH ("TEAL"), with an MDRO of 35,000 Dth/d, and the Parties agree that the Rate Agreement shall provide that for receipts at this Primary Point of Receipt near Clarington, OH, an incremental negotiated reservation charge of \$0.15 per Dth/d shall apply in addition to the otherwise applicable negotiated Reservation Rate set forth in such Rate Agreement. For clarity, TEAL shall not be a Primary Point of Receipt and the incremental negotiated reservation charge of \$0.15 per Dth/d shall not apply if Customer does not provide written notice to Pipeline of Customer's desire to include the TEAL Primary Point of Receipt

Exhibit I.D1.EGDI.TCPL.3

Attachment 5

described above in the Service Agreement by September 1, 2017. If Pipeline receives a borpage 2 of 3 fide third party customer request for firm transportation service that would reduce the capacity available for firm service to Customer utilizing the TEAL Primary Point of Receipt prior to September 1, 2017, Pipeline shall provide prompt written notice of such request to Customer and Customer shall respond to such notice in writing as to whether it desires to include the TEAL Primary Point of Receipt described above in the Service Agreement, by the deadline stated in Pipeline's written notice in lieu of the September 1, 2017 deadline stated above, provided that such deadline shall be not less than five (5) business days from the date of Pipeline's notice".

- 2. Section 7(b)(ii) is amended by deleting the phrase "June 1, 2017" in the second line thereof and replacing it with the phrase "September 1, 2017".
- 3. Section 7(a)(iv) is amended by deleting the phrase "June 1, 2017" in the first and second lines thereof and replacing it with the phrase "September 1, 2017".

[Signature page follows]

Filed: 2017-11-13

EB-2017-0086

Exhibit I.D1.EGDI.TCPL.3

Attachment 5

IN WITNESS WHEREOF, the Parties have caused their duly authorizedge 3 of 3 representatives to execute this Amendment as of the date first written above.

NEXUS Gas Transmission, LLC

Enbridge Gas Distribution Inc.

By: Spectra Energy NEXUS Management,

LLC, in its capacity as operator

Name: Brian R. Millerlie Title: V.P.

Name: Title:

Kerry Lakatos-Hayward Director, Energy Supply and Gas Storage

FIFTH AMENDMENT TO RESTATED PRECEDENT AGREEMENT

This Fifth Amendment to Restated Precedent Agreement (this "Amendment") is made and entered into as of August 17, 2017 between NEXUS Gas Transmission, LLC, (successor in interest to DTE Pipeline Company and Spectra Energy Transmission, LLC) ("Pipeline"), and Enbridge Gas Distribution Inc. ("Customer"). Pipeline and Customer are sometimes referred to individually as a "Party" and collectively as the "Parties". Capitalized terms used but not otherwise defined herein have the meaning given to them in the Precedent Agreement, as defined below.

RECITALS

WHEREAS, the Parties entered into that certain Restated Precedent Agreement dated December 17, 2014 (as the same has been amended from time to time, the "<u>Precedent Agreement</u>"), for the purpose of setting forth the terms according to which Customer would commit to, and Pipeline would provide to Customer, firm Transportation Service on the Project; and

WHEREAS, the Parties wish to amend the Precedent Agreement as specified herein, and to clarify their mutual intent with respect to a previous amendment to the Precedent Agreement.

NOW, THEREFORE, for good and valuable consideration, the receipt of which is hereby acknowledged by the Parties as sufficient and received, the Parties hereby agree that the Precedent Agreement shall be amended as follows in Sections 1-4, effective as of the date indicated above, and a previous amendment is clarified as follows in Section 5, with the Precedent Agreement remaining otherwise in full force and effect in accordance with its terms:

- 1. Section 3(b)(iii) is amended by:
- a. deleting the phrase "35,000 Dth/d" in subsection (C) and replacing it with the phrase "55,000 Dth/d"; and
- b. deleting the phrase "September 1, 2017" each time it appears therein and replacing it with the phrase "December 1, 2017".
- 2. Section 6 is amended by adding the following sentence immediately prior to the last sentence that begins with "Subject to Section 9(a)": "Notwithstanding anything to the contrary in the forgoing, the Parties agree that in the event that the Service Commencement Date does not occur on or prior to the Estimated Service Commencement Date, then the Service Commencement Date shall be a date that is the later of April 1, 2018 or such other date as notified by Pipeline to Customer in accordance with Section 4 in the In-Service Date Notice, except to the extent that the Project Facilities are completed and ready for the provision of the firm transportation service provided for herein and in the Service Agreement prior to April 1, 2018 and the Parties agree to a Service Commencement Date occurring prior to April 1, 2018."
- 3. Section 7(b)(ii) is amended by deleting the phrase "September 1, 2017" and replacing it with the phrase "December 1, 2017".

EXECUTION VERSION

- 4. Section 7(b)(iv) is amended by deleting the phrase "September 1, 2017" and replacing it with the phrase "December 1, 2017".
- 5. With respect to that certain Fourth Amendment to Restated Precedent Agreement, executed by the Parties on May 31, 2017, the Parties agree that Section 3 thereof was intended and understood by each of them to refer to Section 7(b)(iv) of the Precedent Agreement, rather than Section 7(a)(iv).

[Signature Page Follows]

Filed: 2017-11-13, EB-2017-0086, Exhibit I.D1.EGDI.TCPL.3, Attachment 6, Page 3 of 3 **EXECUTION VERSION**

Title:

IN WITNESS WHEREOF, the Parties have caused their duly authorized representatives to execute this Amendment as of the date first written above.

NEXUS Gas Transmission, LLC	Enbridge Gas Distribution Inc.
By: Spectra Energy NEXUS Management, LLC,	0
in its capacity as operator	
By: Brickel	By: Mare
Name:	Name: Dave Charleson

Title: _____

√ice President,

Energy Supply & Customer Care

APPROVED AS TO FORM ENBRIDGE LAW

Exhibit I.D1.EGDI.TCPL.3

Attachment 7 Page 1 of 1

Attachment to EGDI-TCPL 1.1(g) - Updated Landed Cost Analysis

July 2017 - Summery of Landed Cost A	Inelysis (\$C/GI)																			
Apeline	Peth	Pricing Point	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Averag
TCPL/Union	Nia gara-to-Kirkwall-to-Dawn	Niagara	3.19	2.96	2.94	2.98	3.00	3.06	3.14	3.23	3.34	3.46	3.57	3.69	3.82	3.97	4.11	4.26	4.42	3.48
Dawn	Dawn Spot Purchases	Dawn	3.47	3.24	3.21	3.26	3.28	3.48	3.56	3.65	3.76	3.64	3.76	3.88	4.01	4.15	4.30	4.45	4.61	3.75
TCPL - LTFP	Empress-to-Union SWDA	Empre ss	3.42	3.29	3.28	3.33	3.36	3.40	3.48	3.57	3.69	3.81	3.98	4.05	4.18	4.33	4.48	4.63	4.79	3.83
Vector	Chicago-to-Dawn	Chicago	3.72	3.49	3.50	3.55	3.60	3.65	3.72	3.82	3.98	4.05	4.17	4.29	4.43	4.57	4.73	4.88	5.08	4.07
NEXUS (-15%)	Dominion South-to-Milford Junction-to-Dawn	Dominion South	3.97	3.74	3.63	3.65	3.71	3.76	3.83	3.93	4.04	4.16	4.28	4.41	4.55	4.70	4.85	5.00	5.16	4.20
Rover	Dominion South-to-Dawn	Dominion South	4.00	3.77	3.67	3.68	3.74	3.79	3.86	3.96	4.07	4.19	4.31	4.43	4.57	4.72	4.87	5.02	5.18	4.22
NEXUS (Anchor)	Dominion South-to-Milford Junction-to-Dawn	Dominion South	4.07	3.84	3.73	3.75	3.81	3.85	3.98	4.08	4.14	4.26	4.38	4.51	4.65	4.80	4.95	5.10	5.26	4.30
NEXUS (Base)	Dominian South-to-Milford Junction-to-Dawn	Dominion South	4.09	3.86	3.75	3.76	3.82	3.87	3.95	4.04	4.16	4.28	4.40	4.52	4.67	4.81	4.97	5.12	5.28	4.32
NEXUS (+15%)	Dominion South-to-Milford Junction-to-Dawn	Dominion South	4.20	3.98	3.87	3.88 4.13	3.94	3.99	4.07	4.16	4.28	4.40	4.52	4.64	4.78 5.08	4.98	5.09	5.24	5.40	4.43
Alliance	Alliance Trading-to-Border-to-Chicago-to-Dawn	Alliance Trading	4.26	4.07	4.08		4.16	4.21				-				5.19				-
TCPL ANREs st	Empre ss-to-Union SWDA Lee sville-to-Dawn	Empress Dominion South	4.48 N/A	4.35 N/A	4.34 N/A	4.39 N/A	4.42 N/A	4.45 N/A	4.54 N/A	4.63 N/A	4.75 N/A	4.87 N/A	4.99 N/A	5.11 N/A	5.24 N/A	5.39 N/A	5.54 N/A	5.69 N/A	5.85 N/A	4.89 N/A
ANNERS	Lee Sviil e-to-Dawn	Dominion South	IN/ A	IV/A	IN/ A	IV/A	IN/ A	IN/ A	IVA	IVA	IVA	IVA	IVA	IN/A	IV/A	IN/A	N/A	IN/A	N/A	N/A
Average Commodity Prices (\$C/GJ)																				
Priding Point			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Averag
Alliance Trading			2.52	2.34	2.36	2.40	2.43	2.48	2.55	2.64	2.75	2.87	2.98	3.10	3.23	3.37	3.52	3.66	3.81	2.88
Ohicago			3.38	3.16	3.16	3.21	3.26	3.31	3.38	3.47	3.58	3.70	3.82	3.94	4.07	4.22	4.37	4.51	4.67	3.72
Dewn			3.47	3.24	3.21	3.26	3.28	3.48	3.56	3.65	3.76	3.64	3.76	3.88	4.01	4.15	4.30	4.45	4.61	3.75
Dominion South			2.97	2.76	2.65	2.67	2.72	2.77	2.84	2.94	3.05	3.16	3.28	3.40	3.53	3.67	3.82	3.97	4.12	3.20
Empress			2.55	2.42	2.42	2.45	2.49	2.53	2.60	2.70	2.81	2.92	3.04	3.15	3.28	3.42	3.57 3.72	3.72 3.86	3.87 4.02	2.94
Niagara			2.80	2.57	2.54	2.59	2.61	2.6/	2./4	2.84	2.95	3.06	3.18	5.50	5.45	3.57	5.72	5.80	4.02	3.08
Average Foreign Exchange Rate																				
CS/US\$			2018 1.267	2019 1.264	2020 1.261	1.260	1.259	2023 1.258	1.258	2025 1.259	2026 1.261	1.264	2028 1.268	2029 1.271	2030 1.276	2031 1.281	2032 1.285	2033 1.289	1.291	Averag 1.269
G/G3			1.20/	1204	1.201	1200	1.259	1.230	1.230	1.259	1 201	1.204	1.200	12/1	12/0	1 201	1.200	1.289	1.291	1209
Average Demand Charge (C\$/GJ)																				
Ripeline	Path		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Averag
Alliance	Alliance Trading-to-Border		0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597
Alliance	Border-to-Chicago		0.634	0.633	0.631	0.631	0.631	0.630	0.630	0.631	0.631	0.633	0.635	0.637	0.639	0.642	0.644	0.645	0.647	0.635
NEXUS (Base)	Dominian South-to-Milford Junction		0.840	0.838	0.837	0.836	0.835	0.835	0.835	0.835	0.837	0.839	0.841	0.843	0.847	0.850	0.853	0.855	0.857	0.842
NEXUS (Base)	Milford Junction-to-Dawn		0.192	0.192	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.192	0.192	0.193	0.194	0.194	0.195	0.195	0.196	0.192
NEXUS (Anchor)	Dominian South-to-Milford Junction		0.822	0.820	0.819	0.818	0.818	0.817	0.817	0.817	0.819	0.821	0.823	0.825	0.829	0.832	0.835	0.837	0.838	0.824
NEXUS (Anchor)	Milford Junction-to-Dawn		0.192	0.192	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.192	0.192	0.193	0.194	0.194	0.195	0.195	0.196	0.192
NEXUS (+15%)	Dominian South-to-Milford Junction		0.957	0.955	0.953	0.952	0.952	0.951	0.951	0.952	0.953	0.955	0.958	0.961	0.965	0.968	0.972	0.974	0.976	0.959
NEXUS (+19%) NEXUS (-15)	Milford Junction to Dewn Dominion South-to-Milford Junction		0.192	0.192	0.101	0.101	0.191	0.191	0.191	0.719	0.191	0.102	0.102	0.195	0.124	0.104	0.135	0.125	0.196	0.192
NEXUS (-15%)	Milford Junction-to-Dawn		0.725	0.192	0.720	0.719	0.719	0.719	0.191	0.191	0.191	0.192	0.724	0.193	0.194	0.732	0.195	0.195	0.757	0.723
Rover	Dominion South-to-Dawn		0.960	0.958	0.956	0.955	0.955	0.954	0.954	0.955	0.956	0.958	0.961	0.964	0.968	0.971	0.975	0.977	0.979	0.962
TCPL	LH Emore se-to-Union SWDA		1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654
TCPL	LTFP Empress-to-Union SWDA		0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770
TCPL	Nia gara-to-Kirkwall		0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221
UNION (M12X)	Kirkwall-to-Dawn		0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139
Vector	Chicago-to-St. Clair		0.288	0.287	0.287	0.285	0.285	0.285	0.285	0.285	0.287	0.287	0.288	0.289	0.290	0.292	0.293	0.293	0.294	0.289
Vector	St. Clair-to-Dawn		0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Average Abandonment/ACA Charge	rcsen																			
Pipeline	Path		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Averag
Alliance	Alliance Trading-to-Border		0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
NEXUS	Dominion South-to-Milford Junction		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Rover	Dominion South-to-Dawn		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
TCPL	Empress-to-Union SWDA		0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176
TCPL	Nia gara-to-Kirkwall		0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Vector	Chicago-to-St. Clair		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Vector	St. Clair-to-Dawn		0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.000
Average Fuel Ratio																				
Ripeline	Peth		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Averag
Alliance	Alliance Trading-to-Border		4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
Alliance	Border-to-Chicago		1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%	1.33%
NEXUS (Base)	Dominion South-to-Milford Junction		2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2,10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (Base)	Milford Junction-to-Dawn		0.46%	0.45%	0.45%	0.45%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.45%	0.45%	0.45%	0.45%	0.48%	0.45%	0.45%	0.46%
NEXUS (Anchor)	Dominion South-to-Milford Junction		2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (Anchor)	Milford Junction-to-Dawn		0.45%	0.45%	0.45%	0.45%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.45%	0.45%	0.45%	0.45%	0.45%	0.45%	0.48%	0.45%
NEXUS (+15%)	Dominion South-to-Milford Junction		2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (+15%)	Milford Junction-to-Dawn		0.45%	0.45%	0.45%	0.45%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.45%	0.45%	0.45%	0.45%	0.48%	0.46%	0.45%	0.469
NEXUS (-15)	Dominion South-to-Milford Junction		2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%	2.10%
NEXUS (-15%)	Milford Junction-to-Dawn		0.46%	0.45%	0.45%	0.45%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.46%	0.45%	0.45%	0.46%	0.45%	0.45%	0.45%	1.80%
Rover	Dominion South-to-Dawn		1.80%		1.80%	1.80%		1.80%	1.80%			1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80%	1.80% 4.08%
TCPL	Empress-to-Union SWDA		4.03%	4.08%		4.08%	4.03%	4.03%	4.03%	4.03%	4.03%	4.05%	4.08%	4.05%	4.05%	4.03%	4.05%	4.05%	4.08%	-
TCPL	Nia gara-to-Kirkwall		0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%	0.22%
UNION (M12X) Vector	Kirkwall-to-Dawn Chicago-to-St. Clair		0.42%	0.42%	0.42%			0.42%										0.42%		1.05%

Corrected: 2017-11-24, EB-2017-0086, Exhibit I.D1.EGDI.TCPL.3, Attachment 8, Page 1 of 1

November 2017 (revised) - Summary of Landed Cost Analysis (\$C/GI)																				
Pipeline	Path	Pricing Point	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Average
TCPL/Union	Niagara-to-Kirkwall-to-Dawn	Niagara	3.19	2.96	2.93	2.96	3.01	3.06	3.12	3.19	3.27	3.37	3.46	3.59	3.70	3.81	3.93	4.05	4.18	3.40
Dawn	Dawn Spot Purchases	Dawn	3.47	3.24	3.21	3.23	3.28	3.52	3.58	3.65	3.73	3.80	3.90	4.03	4.13	4.25	4.37	4.49	4.62	3.79
TCPL - LTFP	Empress-to-Union SWDA	Empress	3.29	3.23	3.19	3.26	3.32	3.23	3.29	3.36	3.44	3.53	3.63	3.76	3.87	3.98	4.11	4.23	4.37	3.59
Vector	Chicago-to-Dawn	Chicago	3.74	3.55	3.51	3.55	3.60	3.66	3.72	3.79	3.87	3.96	4.07	4.19	4.30	4.42	4.54	4.66	4.79	3.99
NEXUS (-15%)	Dominion South-to-Milford Junction-to-Dawn	Dominion South	3.98	3.83	3.73	3.72	3.77	3.83	3.89	3.96	4.04	4.14	4.24	4.37	4.48	4.60	4.72	4.85	4.98	4.18
Rover	Dominion South-to-Dawn	Dominion South	4.01	3.86	3.76	3.76	3.81	3.86	3.92	3.99	4.08	4.17	4.27	4.41	4.51	4.63	4.75	4.88	5.01	4.22
NEXUS (Anchor)	Dominion South-to-Milford Junction-to-Dawn Dominion South-to-Milford Junction-to-Dawn	Dominion South	4.08	3.93 3.95	3.83 3.84	3.82 3.84	3.87 3.89	3.93 3.94	3.99 4.01	4.06 4.08	4.14	4.24 4.26	4.34 4.36	4.47	4.58 4.60	4.70 4.72	4.82 4.84	4.95 4.97	5.08 5.10	4.28 4.30
NEXUS (Base) NEXUS (+15%)	Dominion South-to-Milford Junction-to-Dawn	Dominion South Dominion South	4.09 4.21	4.06	3.96	3.96	4.01	4.06	4.01	4.06	4.16 4.28	4.20	4.48	4.49 4.61	4.72	4.72	4.96	5.09	5.22	4.42
Alliance	Alliance Trading-to-Border-to-Chicago-to-Dawn	Alliance Trading	3.91	3.89	3.80	3.88	3.96	4.16	4.12	4.30	4.38	4.48	4.59	4.72	4.72	4.03	5.09	5.22	5.36	4.46
TCPL	Empress-to-Union SWDA	Empress	4.35	4.29	4.25	4.32	4.38	4.29	4.35	4.42	4.50	4.59	4.69	4.82	4.93	5.04	5.17	5.29	5.43	4.65
ANR East	Leesville-to-Dawn	Dominion South	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Average Commodity Prices (\$C/GJ)																				
Pricing Point			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Average
Alliance Trading			2.20	2.19	2.10	2.17	2.25	2.44	2.49	2.56	2.64	2.73	2.83	2.96	3.06	3.17	3.29	3.41	3.54	2.71
Chicago			3.41	3.22	3.17	3.21 3.23	3.27	3.32	3.38	3.45	3.53	3.63	3.72	3.85	3.96	4.07	4.19	4.32 4.49	4.45	3.66
Dawn Dominion South			3.47 2.99	3.24 2.85	3.21 2.75	2.75	3.28 2.80	3.52 2.85	3.58 2.91	3.65 2.98	3.73 3.06	3.80 3.15	3.90 3.25	4.03 3.37	4.13 3.48	4.25 3.59	4.37 3.71	3.83	4.62 3.96	3.79 3.19
Empress			2.45	2.39	2.75	2.73	2.48	2.38	2.44	2.50	2.59	2.68	2.78	2.90	3.01	3.12	3.24	3.36	3.49	2.74
Niagara			2.80	2.57	2.54	2.57	2.62	2.68	2.73	2.80	2.88	2.97	3.07	3.20	3.30	3.41	3.53	3.66	3.79	3.01
Average Foreign Exchange Rate			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Average
C\$/US\$			1.259	1.258	1.256	1.256	1.257	1.257	1.257	1.259	1.260	1.263	1.266	1.269	1.271	1.273	1.275	1.276	1.277	1.264
Average Demand Charge (C\$/GJ)																				
Pipeline	Path		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Average
Alliance	Alliance Trading-to-Border		0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597	0.597
Alliance	Border-to-Chicago		0.631	0.630	0.629	0.629	0.629	0.630	0.630	0.630	0.631	0.632	0.634	0.635	0.636	0.637	0.638	0.639	0.639	0.633
NEXUS (Base)	Dominion South-to-Milford Junction		0.836	0.835	0.834	0.834	0.834	0.834	0.834	0.835	0.836	0.838	0.840	0.842	0.843	0.845	0.846	0.847	0.847	0.839
NEXUS (Base)	Milford Junction-to-Dawn		0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.192	0.192	0.192	0.193	0.193	0.193	0.194	0.194	0.192
NEXUS (Anchor)	Dominion South-to-Milford Junction		0.818	0.817	0.816	0.816	0.816	0.816	0.816	0.817	0.818	0.820	0.822	0.824	0.825	0.826	0.828	0.828	0.829	0.821
NEXUS (Anchor)	Milford Junction-to-Dawn		0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.192	0.192	0.192	0.193	0.193	0.193	0.194	0.194	0.192
NEXUS (+15%)	Dominion South-to-Milford Junction		0.952	0.951	0.950	0.950	0.950	0.950	0.951	0.951	0.953	0.955	0.957	0.959	0.961	0.962	0.964	0.965	0.965	0.956
NEXUS (+15%)	Milford Junction-to-Dawn		0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.192	0.192	0.192	0.193	0.193	0.193	0.194	0.194	0.192
NEXUS (-15)	Dominion South-to-Milford Junction		0.719	0.718	0.718	0.717	0.718	0.718	0.718	0.719	0.720	0.721	0.723	0.725	0.726	0.727	0.728	0.729	0.729	0.722
NEXUS (-15%)	Milford Junction-to-Dawn		0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.191	0.192	0.192	0.192	0.193	0.193	0.193	0.194	0.194	0.192
Rover	Dominion South-to-Dawn		0.955	0.954	0.953	0.953	0.953	0.953	0.953	0.954	0.956	0.958	0.960	0.962	0.964	0.965	0.967	0.968	0.968	0.959
TCPL	LH Empress-to-Union SWDA		1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654	1.654
TCPL	LTFP Empress-to-Union SWDA		0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770	0.770
TCPL	Niagara-to-Kirkwall		0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221	0.221
UNION (M12X)	Kirkwall-to-Dawn		0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139	0.139
Vector	Chicago-to-St. Clair		0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.286	0.287	0.287	0.288	0.289	0.289	0.290	0.290	0.290	0.290	0.287
Vector	St. Clair-to-Dawn		0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019
Average Abandonment/ACA Charge (C\$/GJ)																				
Pipeline	Path		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Average
Alliance	Alliance Trading-to-Border		0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
NEXUS	Dominion South-to-Milford Junction		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Rover	Dominion South-to-Dawn		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
TCPL	Empress-to-Union SWDA		0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176	0.176
TCPL	Niagara-to-Kirkwall		0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
Vector	Chicago-to-St. Clair		0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Vactor				0.0004		0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.000
Vector	St. Clair-to-Dawn																			
Average Fuel Ratio																				
Average Fuel Ratio Pipeline	Path		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Average
Average Fuel Ratio Pipeline Alliance	Path Alliance Trading-to-Border		2018 4.75%	2019 4.75%	2020 4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%
Average Fuel Ratio Pipeline Alliance Alliance	Path Alliance Trading-to-Border Border-to-Chicago		2018 4.75% 1.33%	2019 4.75% 1.33%	2020 4.75% 1.33%	4.75% 1.33%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction		2018 4.75% 1.33% 2.10%	2019 4.75% 1.33% 2.10%	2020 4.75% 1.33% 2.10%	4.75% 1.33% 2.10%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dawn		2018 4.75% 1.33% 2.10% 0.31%	2019 4.75% 1.33% 2.10% 0.31%	2020 4.75% 1.33% 2.10% 0.31%	4.75% 1.33% 2.10% 0.31%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction		2018 4.75% 1.33% 2.10% 0.31% 2.10%	2019 4.75% 1.33% 2.10% 0.31% 2.10%	2020 4.75% 1.33% 2.10% 0.31% 2.10%	4.75% 1.33% 2.10% 0.31% 2.10%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction Milford Junction-to-Dawn		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (A15%)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (A15%) NEXUS (415%)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction Moreover South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Dewn		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (415%) NEXUS (+15%) NEXUS (-15)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10%													
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (4-15%) NEXUS (-15%) NEXUS (-15%)	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dawn		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 0.31%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 0.31%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (4-15%) NEXUS (-15%) NEXUS (-15%) NEXUS (-15%) ROVER	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 0.31% 1.80%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.10%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%							
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (A15%) NEXUS (4-15%) NEXUS (4-15%) NEXUS (5-15%) NEXUS (5-15%) NEXUS (5-15%) NEXUS (5-15%) ROver TCPL	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction Milford Junction-to-Bawn Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Milford Junction Milford Junction-to-Dawn Dominion South-to-Dawn Dominion South-to-Dawn Empress-to-Union SWDA		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80% 3.02%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80% 3.02%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80% 3.02%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80% 3.02%														
Average Fuel Ratio Pipeline Alliance Alliance NEXUS (Base) NEXUS (Base) NEXUS (Anchor) NEXUS (Anchor) NEXUS (4-15%) NEXUS (-15%) NEXUS (-15%) NEXUS (-15%) ROVER	Path Alliance Trading-to-Border Border-to-Chicago Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction Milford Junction-to-Dewn Dominion South-to-Milford Junction		2018 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	2019 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 0.31% 1.80%	2020 4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.10%	4.75% 1.33% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 2.10% 0.31% 1.80%							

Exhibit I.D1.EGDI.TCPL.4

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TCPL INTERROGATORY #4

<u>INTERROGATORY</u>

IR Number: Interrogatory #4

Reference: 1) Exhibit D1, Tab 2, Schedule 11, Page 6 of 14

Preamble: In Reference 1, EDGI states:

"exploring opportunities such as contracting for capacity on pipelines that deliver to Dawn, as described elsewhere in the 2018 gas supply evidence, or to allow for the utility's winter requirement at Dawn to be

shifted to the summer months by contracting for a level of incremental storage capacity, or shorter term hybrid seasonal

exchanges at Dawn. In the longer-term, additional diversity could be achieved through contracting for new transportation services to Dawn, or through the acquisition of supply points other than Dawn

such as Iroquois should it become a more liquid hub".

Request:

- a) Please confirm the EGDI Precedent Agreement with NEXUS allows EGDI to increase its maximum daily quantity (MDQ) by 40,000 Dth/d. If not confirmed, please detail whether or not EDGI has an option or options to increase MDQ and provide the details, including option end date(s) and volume(s).
- b) Has EGDI conducted any analysis on increasing its NEXUS capacity as part of its stated intention to explore long term transportation services in Reference 1? Please provide any such analysis. If EGDI has not conducted an analysis, please state whether EGDI plans to conduct such analysis; and, if so, when.

RESPONSE

a) Confirmed, the NEXUS agreement provides EGDI with the option to increase its contracted capacity by 40,000 Dth per day subject to the capacity being available. If the election is made effective with the Phase II Service Commencement Date then EGDI will benefit from the Most Favored Nations provision which provide access to more favourable rate provisions and terms of service that have been negotiated by other NEXUS contracting parties. EGDI can also make the election effective after the Phase II Service Commencement Date but prior to October 31,

Witness: D. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D1.EGDI.TCPL.4

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2020 and gain access to the reservation rate negotiated by Union Gas as an anchor shipper.

b) The 110,000 Dth per day of NEXUS transportation capacity that EGDI contracted provides for a balance of reliability, diversity, flexibility and cost in the context of its current gas transportation portfolio as evidenced in the Board's pre-approval of the cost consequences. EGDI intends to continue observing the evolution of the North American natural gas marketplaces before determining if incremental NEXUS capacity would benefit its transportation portfolio.

Witness: D. Small

Exhibit I.D1.EGDI.TCPL.5

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TCPL INTERROGATORY #5

<u>INTERROGATORY</u>

IR Number: Interrogatory #5

Reference: 1) Exhibit D1, Tab 2, Schedule 2, Page 22 of 27

Preamble: In Reference 1, EGDI states:

"Price assumptions reflect the market's assessment (at the time evidence is prepared) of the various expected delivery points in the Company's gas supply plan. The market's assessment can be determined at any point in time by the use of a simple average of forward quoted prices as reported by various media and other services, over a period of 21 business days for a basket of pricing points and pricing indices that reflect the Company's gas supply

acquisition arrangements".

Request: a) Please list the "various media and other services" noted in

Reference 1. Are these sources the same as those used for EGDI's landed cost analyses? If not, please list the sources EGDI

utilizes in its landed cost analyses.

RESPONSE

EGD's price assumptions come from its internal system called OpenLink, which reports forward curves reported by sources such as: Canadian Gas Price Monitor, Inside FERC, NGX, ICE, and Gas Daily. These are the same sources used in EGD's landed cost analyses.

Witness: D. Small

Exhibit I.D2.EGDI.STAFF.15

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BOARD STAFF INTERROGATORY #15

INTERROGATORY

Ref: 2018 Discontinuance of Site Restoration Cost Rider (Rider D) Exhibit D2 / Tab 2 / Schedule 1

Question(s):

a) Please confirm whether OEB staff's understanding set out below is correct. If the tax impact of Rider D is included in rates now, the 2018 allowed revenue amount would be reduced by \$11.2 million and a forecast \$4 million debit will be requested for recovery at the time that the Constant Dollar Net Salvage Adjustment Deferral Account is brought forward for disposition.

RESPONSE

Confirmed. Assuming Rider D is discontinued at the end of 2017, but the 2018 tax impact of the originally approved 2018 Rider D amount of \$31.1 million is included within the determination of 2018 allowed revenues and rates (as opposed to refunded through the Constant Dollar Net Salvage Adjustment Deferral Account), the 2018 allowed revenue amount would decrease by approximately \$11.2 million as compared to the as-filed allowed revenue amount within this proceeding, and the resultant amount to be recovered through the Constant Dollar Net Salvage Adjustment Deferral Account would be forecast at approximately \$4 million.

Witnesses: A Mandyam

R. Small

Exhibit I.D2.EGDI.APPrO.2

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APPrO INTERROGATORY #2

INTERROGATORY

Reference: i) Exhibit D2 Tab 2 Schedule 1 Discontinuance of Site Restoration Cost Rider (Rider D) in 2018

Preamble: Enbridge proposes to discontinue the Rate Rider D credit to customers one year ahead of the original approved schedule, as the total amount of the refund is now expected to be exhausted by the end of 2017. APPrO would like information to demonstrate how these funds were originally intended to be distributed and information to compare how the actual funds were actually distributed by rate class.

a) For each year from 2014 to 2018 please complete the following table to compare the projected forecast and actual SRC credit amounts and volumes by rate class. Please ensure you provide complete information for each rate class, including Rate 125 for each year:

	Year (provide a	separate ta	ble for eacl	n year 2014	to 2018)	
	,	Rate Cla	ss (include	all applicat	ole rate clas	sses)	TOTAL
1	Forecast Volume ¹ (m ³)						
2	Forecast Rate Rider D ¹ (\$/m3)						
3	Forecast Credit (\$)						
4	Actual Volume 23						
5	Actual Rate Rider D ³ (\$/m3)						
6	Actual Credit (\$)						
7	Volume						
	Variance						
	(Actual-						
	Forecast) (m3)						
8	Credit Variance (Actual-						
	Forecast) (\$)						

Table 1 Forecast and Actual SRC Credit by Year

Witnesses: R. Cheung

Exhibit I.D2.EGDI.APPrO.2

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Notes

- 1. Provide forecast volume and Rate Rider amounts by rate class based on the original EB-2012-0459 filing. If a volume for any specific year was not forecast during this proceeding, then provide the annual volume and/or Rate Rider forecast at the time of the specific year's rate filing. For 2018, assume that the Actual Rate Rider is zero as proposed. If the Rate Rider was not forecast for any specific year, then calculate the Rate Rider based on the EB-2012-0459 forecasted credit amount and the forecast volume.
- 2. For 2017, please provide projected annual volume to year end.
- 3. Assume that Actual Volumes are the same as the Forecast Volume for 2018.
- b) Please summarize the information provided in Table 1 in a) above illustrating the variances from forecast by rate class by year.

	Credit	Variance (Ad	ctual-Forecas	st) (\$) From T	able 1							
	Rate	e Class (inclu	de all applica	able rate clas	ses)	TOTAL						
2014												
2015												
2016												
2017												
2018												
Sum												
2014-												
2018												

Table 2 SRC Variance by Rate Class

c) Please summarize the volume variances from Table 1 in a) above by rate classes in the table below.

	Volume Varia	ance (Actual-Fo	recast) (\$) Froi	m Table 1								
	Rate Clas	s (include all ap	pplicable rate cl	asses)	TOTAL							
2014												
2015												
2016												
2017												
2018												
Sum												
2014-												
2018												

Table 3 Volume Variances Among Rate Classes

d) Assuming that the Board required Enbridge to true-up the credits by rate class to match the forecasted amounts, please provide alternative reasonable methodologies to make such true-ups, and specify any resulting adjustments.

Witnesses: R. Cheung

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D2.EGDI.APPrO.2

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e) When did Enbridge first notice that SRC payments were exceeding forecast and describe any resulting actions taken.

RESPONSE

a) Tables 1 to 5 provide the forecast and actual Rider D SRC credit for the years from 2014 to 2018.

Witnesses: R. Cheung

Exhibit I.D2.EGDI.APPrO.2

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			TABLE 1:	2014 (00	T - DEC) !	SITE REST(TABLE 1: 2014 (OCT - DEC) SITE RESTORATION COST RIDER - ACTUAL VS FORECAST	OST RIDE	R-ACTU/	AL VS FORE	CAST				
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
NO NO		Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 300 Int	Total
L i	Forecast Volumes (10³m³)	1,083,679	1,089,720	158	0	153,852	116,102	1	20,235	42,807	117,216	41,033		6,919	2,671,720
5	Contract Demand Volumes Forecast (10³m³)	ı						29,806					47		29,853
ന്	Board-Approved Rates Rider D (\$/m³)	0.065211	0.021419	0.007776	0.021419	0.006149	0.003543	0.032527	0.000390	0.004411	0.001383	0.002829	0.137590	0.004500	
4;	Approved Credit (\$'000)	\$ 70,667	\$ 23,341	\$	0 \$	\$ 946	\$ 411	\$ 696	&	\$ 189	\$ 162	\$ 116	9 \$	\$ 31	\$ 96,849
r,	Actual Volumes (10³m³)	1,511,561	1,521,408	126	898	145,872	138,965	1	21,694	28,686	115,083	52,437		10,106	3,546,807
9	Contract Demand Volumes Actual $(10^3 m^3)$							29,806					47		29,853
7.	Actual Credit (\$'000)	\$ 98,729	\$ 32,650	\$	\$ 19	\$ 891	\$ 480	696 \$	&	\$ 127	\$ 159	\$ 149	9 \$	\$ 45	\$ 134,233
œ	Volumetric Variance $(10^3 m^3)$	427,882	431,689	(32)	898	(2,980)	22,864	0	1,459	(14,121)	(2,133)	11,404	0	3,187	875,087
റ്	Credit Variance (\$'000)	\$ 28,061	\$ 9,309	(0) \$	\$ 19	\$ (55)	\$	0 \$	\$ 1	\$ (62)	\$ (3)	\$ 32	0 \$	\$ 14	\$ 37,384

Witnesses: R. Cheung A. Kacicnik

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	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 300 Int	Total
Forecast Volumes (10³m³)	4,673,421	4,662,431	510	0	477,711	504,807	,	56,056	133,192	471,137	169,087	ı	30,000	11,178,352
Contract Demand Volumes Fore cast (10^3m^3)	' nmes	ı					119,224			1		187		119,411
Board-Approved Rates Rider D (\$/m³)	0.014058	0.004754	0.002023	0.004754	0.001434	0.000815	0.007986	0.000138	0.001067	0.000336	0.000822	0.031701	0.000919	
Approved Credit (\$ '000)	\$ 62,699	\$ 22,164	\$ 1	\$ 0	\$ 685	\$ 411	\$ 952	\$	\$ 142	\$ 158	\$ 139	9 \$	\$ 28	\$ 90,392
Actual Volumes (10³m³)	4,921,588	4,919,216	304	3,472	680,665	512,632	1	68,473	74,668	395,971	176,403		26,780	11,780,173
Contract Demand Volumes $Actual (10^3 m^3)$	'nmes	ı		,		,	119,224	1	,	ı	ı	187		119,411
Actual Credit (\$'000)	\$ 69,131	\$ 23,553	\$ 1	\$ 17	\$ 978	\$ 416	\$ 952	\$	\$ 78	\$ 134	\$ 145	9 \$	\$ 25	\$ 95,444
Volumetric Variance (10³m³)	248,167	256,785	(506)	3,472	202,953	7,825	0	12,417	(58,524)	(75,165)	7,316	0	(3,220)	601,821
Credit Variance (\$'000)	\$ 3,432	\$ 1,389	(0)	\$ 17	\$ 293	\$	(0) \$	\$ 5	\$ (64)	\$ (24)	9	(0)	(3)	\$ 5,052

Witnesses: R. Cheung A. Kacicnik

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			71	ABLE 3: 20	16 SITE RI	STORATIO	TABLE 3: 2016 SITE RESTORATION COST RIDER - ACTUAL VS FORECAST	RIDER - AC	TUAL VS F	-ORECAST					
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
ITEM		Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300	Rate 300 Int	Total
t i	Forecast Volumes (10³m³)	4,870,006	4,796,209	510	0	703,348	517,078	1	59,278	88,566	325,657	170,837	ı	34,992	11,566,480
2	Contract Demand Volumes Forecast (10³m³)							119,224		1			187		119,411
က်	Board-Approved Rates Rider D (\$/m³)	0.012315	0.004373	0.001838	0.004373	0.001396	0.001078	0.009120	0.000126	0.000829	0.000280	0.000914	0.030640	0.000788	
4	Approved Credit (\$'000)	\$ 59,974	\$ 20,973	\$ 1	0 \$	\$ 982	\$ 557	\$ 1,087	\$ 7	\$ 73	\$ 91	\$ 156	9 \$	\$ 28	\$ 83,936
ιγ	Actual Volumes (10³m³)	4,621,553	4,601,819	177	3,375	825,884	495,797	1	63,821	48,321	306,694	169,647	ı	21,095	11,158,184
9	Contract Demand Volumes Actual $(10^3 m^3)$		1	1		1	1	119,224		ı			187		119,411
7.	Actual Credit (\$'000)	\$ 56,963	\$ 20,088	0 \$	\$ 15	\$ 1,160	\$ 528	\$ 1,087	&	\$ 40	\$ 85	\$ 155	9 \$	\$ 17	\$ 80,154
œ	Volumetric Variance (10³m³)	(248,453)	(194,390)	(333)	3,375	122,536	(21,280)		4,543	(40,245)	(18,962)	(1,190)		(13,897)	(408,296)
oi.	Credit Variance (\$'000)	\$ (3,011)	\$ (885)	\$ (1)	\$ 15	\$ 178	\$ (29)	(0) \$	\$ 1	\$ (33)	(9) \$	\$ (1)	0 \$	\$ (11)	\$ (3,782)

Witnesses: R. Cheung A. Kacicnik

(3,442)

2017 annual volumes and credits are based on 8 months of actuals and 4 months of forecasts

74,037

11,236,905 11,752,101 (521,271) Col. 14 119,411 s (22) (34,992) Col. 13 34,992 0.000718 Rate 300 Int s ÷ 9 0.027992 Col. 12 Rate 300 187 187 0 \$ s <u>4</u> 142 137 (5,150)Col. 11 Rate 200 s Ş 61 63 Col. 10 302,174 5,861 Rate 170 \$ Ş TABLE 4: 2017 SITE RESTORATION COST RIDER - ACTUAL VS FORECAST 62) 61 32 (9,945) Col. 9 Rate 145 \$ s Ş 0 Col. 8 2,626 Rate 135 Ş Ş s (49) 964 915 113,149 (6,075) Col. 7 Rate 125 s 478 483 0.000974 Col. 6 5,418 Rate 115 \$ \$ (20) 965 0.001185 1,021 (48,113) 813,322 Col. 5 Rate 110 Ş Col. 4 Rate 100 479 479 Ş Ş 9 0 0.002837 Col. 3 (140) 123 Ş Ś (874) 18,453 4,641,345 (210,317) (220,924) 4,862,269 Col. 2 Rate 6 Ş Ş s (2,413) 4,701,161 0.011277 Col. 1 Contract Demand Volumes Actual (10^3m^3) Contract Demand Volumes Board-Approved Rates Volumetric Variance Fore cast Volumes (10³m³) Approved Credit (\$'000) Actual Volumes¹ Fore cast (10^3m^3) **Credit Variance** Actual Credit¹ (\$ '000) Rider D (\$/m³) $(10^3 m^3)$ (000, \$) NO NO

77,479

Total

Witnesses: R. Cheung A. Kacicnik

	4	_	761	11		31,144	761	11	44		
	Col. 14	Total	11,497,761	111,311		\$ 31,3	11,497,761	111,311	\$ 31,144	0	•
	Col. 13	Rate 300 Int	0		0.000000		0			•	•
	ö	30 30				\$ 5			\$ \$		₩
	Col. 12	Rate 300		187	0.011486	,,		187	,,	0	•
			_			57 \$	-		57 \$	k.	₩
	Col. 11	Rate 200	169,764	1	0.000336	\$	169,764	1	\$	0	100
	10	e 0	152			22	152		22		,
	Col. 10	Rate 170	291,152	'	0.000074	\$	291,152	'	٠	0	•
CAST	Col. 9	Rate 145	50,136		0.000376	19	50,136	,	19	0	
FORE	ŏ	æ ~	22		0.0	❖	20		٠		•
NL VS	Col. 8	Rate 135	64,501		0.000044	3	64,501	,	3	0	•
CTUA	ŭ	2 T	2		0.0	\$	29		٠		\$
TABLE 5: 2018 SITE RESTORATION COST RIDER - ACTUAL VS FORECAST	Col. 7	Rate 125		111,124	0.003312	368		111,124	368	0	•
TRIC			_	Н		151 \$	_	П	151 \$	k	₩
N COS	Col. 6	Rate 115	542,831		0.000278		542,831	•		0	
\TIO	10					\$ 998			\$ 998		٠,
STOR/	Col. 5	Rate 110	789,036	1	0.000464	\$	789,036	'	\$	0	•
TE RE	4	e o			0000	0			0		
18 SI	Col. 4	Rate 100	0	'	0.00000	\$	0	'	\$	0	₩.
5: 20	Col. 3	Rate 9	0		0.000000		0	,		•	
ABLE	ŭ	~			0.0	\$			\$		₩
F	Col. 2	Rate 6	4,829,793		0.001634	7,890	4,829,793		7,890	0	•
	O	<u>. </u>			0.0	\$			\$		s
	Col. 1	Rate 1	4,760,547		0.004677	\$ 22,266	4,760,547	•	\$ 22,266	0	
			4	es	O	\$	4	es	\$		❖
			Forecast Volumes (10³m³)	Contract Demand Volumes Fore cast $(10^3 m^3)$	Board-Approved Rates Rider D (\$/m³)	Approved Credit (\$'000)	Actual Volumes ¹ (10 ³ m³)	Contract Demand Volumes Actual $(10^3 m^3)$	Actual Credit¹ (\$'000)	Volumetric Variance (10³m³)	Credit Variance (\$ '000)
		ITEM	ij	7	က	4	ιςi	9	7.	œί	6

otes 2018 annual volumes and credits are matching with the forecasts.

Witnesses: R. Cheung A. Kacicnik

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D2.EGDI.APPrO.2

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b) Table 6 on the following page summarizes the annual \$millions variance of the SRC credit by rate classes for the years from 2014 to 2017 and the 2018 forecast of \$31.1 million.

As noted in paragraph 8 of Exhibit D2, Tab 2, Schedule 1, it is expected that around \$383.9 million will be credited to ratepayer by the end of 2017.

The total amount of \$35.2 million listed in Row 5 of Table 6 shows the expected recoverable amount if Rider D continues in 2018. The total amount of \$4.1 million listed in Row 7 in the same table shows the expected recoverable amount if Rider D is discontinued in 2018.

Witnesses: R. Cheung

2015 \$ 95,444 2016 \$ 80,154 2017 \$ 74,037 2018 \$ 31,144

2014 to 2018 Total \$ 415,012
Total Forecast \$ 379,800
Total Over-refunded \$ 35,212

					TAB	LE 6	TABLE 6: SITE RESTORATION COST VARIANCE BY RATE CLASS - 2014 TO 2018	STOR	ATIC	N N	JST	VARI.	ANC	E BY F	RATE (CLAS	S - 2	014	TO 2(218								
(000 \$,)		-	Col. 1		Col. 2		Col. 3	Col. 4		Col. 5	2	Col. 6	9.	Col. 7	7.	Col. 8	∞	ŭ	Col. 9	Ö	Col. 10	8	Col. 11	Col. 12		Col. 13	Co	Col. 14
ITEM	Year		Rate 1		Rate 6		Rate 9	Rate 100		Rate 110	0 -	Rate 115	e ro	Rate 125	te 35	Rate 135	a 10	۰٬۱ ۳	Rate 145	R.	Rate 170	R.	Rate 200	Rate 300		Rate 300 Int	To	Total
L i	2014 (Oct - Dec)	\$	\$ 28,061	\$ 1	9,309	\$	(0)	•	19 \$		(52)	\$	89	₩.	0	\$	Н	\$	(62)	\$	(3)	\$	32	\$	\$ 0	14		37,384
5	2015	\$	3,432	\$ 2	1,389	\$	(0)	<.	17 \$		293	<>-	2	٠,	(0)	<.	7	\$	(64) \$	ب	(24)	\$	9	\$	\$ (0)	(3) \$		5,052
κi	2016	<>	(3,011)	1) \$	(882)	\$ (9	(1)		15 \$		178	φ.	(29)	φ.	(0)	₩.	₽	\$	(33)	φ.	(9)	\$	(1)	\$	\$ 0	(11) \$		(3,782)
4;	2017	\$	\$ (2,413)	\$ (8	(874)	\$ (+	(0)	.	2 \$		(99)	\$	2	\$	(49)	\$	0	\$	(29)	\$	1	\$	(4)	₩.	\$ (0)	(25) \$	\$	(3,442)
r.	2014 to 2017 Rider D Variance	ς	\$ 26,069	\$	8,939	\$	(2)	\$	52 \$		360	•	20	•	(49)	•	4	φ.	(188) \$	φ.	(31) \$	- ♦	33	\$	\$ (0)	(25) \$		35,212
9	2018 Forecast	s	\$ 22,266	\$	7,890	\$	1	φ.	\$ 0		366	s	151	s	368	\$	æ	\$	19	s	22	s	57	\$	2			31,144
7.	Net Variance (row 5 -6)	\$	3,803	φ.	1,049	\$	\$ (2)		52 \$		\$ (9)		(101) \$		(417)	ν.	н	1 \$	\$ (202)	ŵ	\$ (23)	φ.	(24) \$		(2) \$	(25)	ŵ	4,069
																									Act	Actual Credits by Year 2014 \$ 134,233	its by \$ 13	<u>Year</u> 4,233

Witnesses: R. Cheung A. Kacicnik

Exhibit I.D2.EGDI.APPrO.2

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c) Table 7 on the following page summarizes the volumetric variance by rate classes from the years from 2014 to 2017.

Witnesses: R. Cheung A. Kacicnik

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				TABLE 7	NOLUM	TABLE 7: VOLUMES VARIANCE BY RATE CLASS - 2014 TO 2018	ICE BY RA	TE CLASS -	2014 TO	2018					
10³m³		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
ITEM	Year	Rate 1	Rate 6	Rate 9	Rate 100	Rate 110	Rate 115	Rate 125 ¹	Rate 135	Rate 145	Rate 170	Rate 200	Rate 300 ¹	Rate 300 Int	Total
∺	2014 (Oct - Dec)	427,882	431,689	(32)	898	(2,980)	22,864	0	1,459	(14, 121)	(2,133)	11,404	0	3,187	875,087
5	2015	248,167	256,785	(506)	3,472	202,953	7,825	0	12,417	(58,524)	(75, 165)	7,316	0	(3,220)	601,821
ю́	2016	(248,453)	(194,390)	(333)	3,375	122,536	(21,280)	0	4,543	(40,245)	(18,962)	(1,190)	0	(13,897)	(408,296)
4	2017	(210,317)	(220,924)	(140)	479	(48,113)	5,418	(6,075)	2,626	(9,945)	5,861	(5,150)	0	(34,992)	(521,271)
ιų	Total Volumetric Variance	217,280	273,160	(710)	8,195	269,397	14,826	(6,075)	21,045	(122,835)	(90,399)	12,381	0	(48,923)	547,341
9	2018 Forecast	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.	Total Volumetric Variance	217,280	273,160	(710)	8,195	269,397	14,826	(6,075)	21,045	(122,835)	(90,399)	12,381	0	(48,923)	547,341
	Notes 1 Contract Demand Volumes for Rates 125 and 300	umes for Rat	tes 125 and 300	0			,	,	,	,	,				

Witnesses: R. Cheung A. Kacicnik

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D2.EGDI.APPrO.2

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d) Once the total amounts cleared and final variances are known through the completion of Fiscal 2017, EGD will bring forward a proposal to clear the final balance in the Constant Dollar Net Salvage Adjustment Deferral Account, currently estimated as \$4.1M.

e) EGD became aware at the end of 2014 that SRC Rider D actual refund exceeded forecast. Given the five year approval of Rider D and the Constant Dollar Net Salvage Adjustment Deferral Account true up method, EGD considered it appropriate to continue monitoring over or under clearances for at least the first few years before it might consider an attempted corrective proposal such as that being proposed at this time.

Witnesses: R. Cheung

A. Kacicnik

Exhibit I.D2.EGDI.BOMA.31

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BOMA INTERROGATORY #31

INTERROGATORY

Ref: Exhibit D2, Tab 2, Schedule 1, p3; Site Restoration Cost Adjustment (Rider D)

- (a) How was Rider D constructed and designed? Please explain the arithmetic used to calculate Rider D in each of 2014, 2015, 2016, and 2017, both forecast and actual.
- (b) Please explain the following sentence (the last sentence in paragraph 9):
 - "The main contributors to the anticipated debt variance balance are the higher actual volumes in 2014 and the higher Rider D unit rates that year versus the other years, partially offset by lower actual volumes in 2016 and 2017 due to warmer than normal weather".
- (c) Please confirm that in eliminating Rider D on December 31, 2017 and creating a deferral account and clearing that account in May 2018 in the ESM proceeding, EGD is removing a credit to rates of \$31.4 million in 2018, and recovering its overpayment of about \$35.1 million one year earlier than otherwise and thereby increasing its 2018 cash flow by about \$66 million, before incorporating the income tax credit to ratepayers.
- (d) What is EGD's most current forecast of the likely actual amount which will be collected from Rider D in 2018 if Rider D is left in place? What has been the amount collected to date, as at October 31st?

RESPONSE

(a) The Site Restoration Credit Clearance unit rates (Rider D) were designed based on the Board Approved cost allocation methodology for the rate base assets which make up the site restoration reserve, primarily services and mains. This approach allows for stability in the year over year amounts which are allocated to each class as the allocators do not change substantially between the rate classes.

Table 1 below illustrates the Site Restoration Credit allocation by rate class for 2017. The allocation of the 2017 amount of \$77.5 million in site restoration credits to the customer rate classes can be seen in Line 4.

Witnesses: K. Culbert

A. Kacicnik

B. Mandyam

R. Small

A. Patel

Exhibit I.D2.EGDI.BOMA.31

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The unit rates were developed based on the 2017 allocated credit amounts to the rate classes (Table 2, Line 5) divided by 2017 Board Approved delivery volumes (Table 2, Line 6 or 7). This same methodology was applied to develop the 2014 to 2016 unit rates. Please also see response to APPrO Interrogatory #2 at Exhibit I.D2.EGDI.APPRO.2.

Witnesses: K. Culbert

A. KacicnikB. Mandyam

R. Small

A. Patel

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D2.EGDI.BOMA.31

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				TAB	LE 1: SITE RI	TABLE 1: SITE RESTORATION CREDIT ALLOCATION DECEMBER 31, 2017	CREDIT ALL	OCATION							
					1	(thousand dollars)	llars)								
		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Ool. 7	Col. 8	00 <u> </u>	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
ITEM		SITE RESTORATION	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE
Ö	DESCRIPTION				6		110	115						300	300 Int
	DISTRIBUTION FACILITIES														
1:1	Delivery Demand TP > 4"	11,323	5,265	4,514	0	0	290	142	957	0	15	12	126	2	0
1.2	Delivery Demand TP <= 4"	1,243	631	541	0	0	32	17	0	0	2	-	15	0	0
1.3	Delivery Demand HP	3,583	1,841	1,578	0	0	101	20	0	0	2	4	0	-	4
1.4	Delivery Demand LP	19,402	896'6	8,547	0	0	548	263	0	-	28	24	0	9	21
1.5	Cust. Rel Plant	15,460	14,262	1,195	0	0	2	0	0	0	0	0	0	0	0
-	Total Mains	51,012	31,968	16,376	0	0	926	47.1	957	7	20	45	141	2	24
2	Services	26,239	23,266	2,887	0	0	45	ις	4	2	Ε	19	0	0	
ю́	Storage Facilities and Measurement and Regulations	228	154	92	0	0	ю	-	7	0	0	0	-	0	0
4	Total Site Restoration Credit	77,479	55,388	19,327	-	0	1,021	478	964	7	61	61	142	2	25
			TABLE 2: C	ETERMINAT	ION OF SITE	TABLE 2: DETERMINATION OF SITE RESTORATION CREDIT CLEARANCE TO CUSTOMERS	ON CREDIT CL	EARANCE TO	CUSTOMER	ø					
				E	ROM JANUAF	FROM JANUARY 1, 2017 TO DECEMBER 31, 2017	DECEMBER 3	11, 2017							
		Sol. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	6 . 100	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14
HEM		SITE RESTORATION	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE	RATE
Ŏ.	DESCRIPTION	CREDIT/ TOTAL	-	9	6	100	110	115	125	135	145	170	200	300	300 Int
5.	Total Site Restoration Credit Clearance to Customers (\$ '000)	77,479	55,388	19,327	-	0	1,021	478	964	7	61	61	142	2	. 52
9	Delivery Volume from January to December (10 $^3\ {\rm m}^3$)	11,752,101	4,911,478	4,862,269	263	0	861,435	490,292		60,899	63,318	296,313	170,843		34,992
7.	Contract Demand from January to December (10^3 m^3)								119,224					187	
∞	Credit to Customers (c/m³)		1.1277	0.3975	0.2837	0.0000	0.1185	0.0974	0.8086	0.0114	0.0958	0.0207	0.0829	2.7992	0.0718

Witnesses: K. Culbert

A. Kacicnik

B. Mandyam

R. Small A. Patel

Exhibit I.D2.EGDI.BOMA.31

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(b) The explanation in the sentence referenced should have said; "The main contributors to the anticipated debit variance balance are the higher actual volumes in 2014 & 2015 and the higher Rider D unit rates in those years versus the other years, partially offset by lower actual volumes in 2016 and 2017 due to warmer than normal weather". Said differently, this means that the total higher than forecast volume variances in 2014 and 2015 was greater than the total lower than forecast volume variances in 2016 and 2017, therefore contributing to the over refund amounts of Rider D in the early years being greater than the under refund amounts in the later years. Also contributing to this is the fact that Rider D unit rates were higher in the earlier years versus later years due to the pattern of higher total annual amounts approved for return to customers by the Board during the early years as compared to the later years.

- (c) The proposal to cease Rider D at the end of 2017 will in fact avert a negative cash flow to the Company in 2018. With the expectation that at the end of 2017 the Company will have refunded more than the total \$379.8 million approved for refund (which amounts to a total negative cash flow to the Company over the four years), any additional refunds in 2018 would result in a further negative cash flow to the Company, which would need to be recovered in 2019.
- (d) Rider D is approved and designed for a crediting of amounts to customers not recovery of amounts. If Rider D was left in place for 2018, it would be designed to return \$31.1 million (as originally approved in EB-2012-0459) utilizing the forecast volumes included within this proceeding. The Company's updated actual to date cumulative balance of Rider D refunds at October 31, 2017 + remaining 2 months is an estimated over-credit of \$ (3.7) million.

Witnesses: K. Culbert

A. Kacicnik B. Mandyam R. Small

A. Patel

Exhibit I.D2.EGDI.BOMA.32

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BOMA INTERROGATORY #32

INTERROGATORY

Ref: Exhibit D2, Tab 1, Schedule 1, p20

- (a) Please explain the intent and rationale for the proposal to record a credit of \$11.2 million payable to ratepayers in the 2018 CDNSADA and to remove it from forecast \$31.1 million tax reduction from the termination of the update of forecast 2018 allowed revenues in forecast.
- (b) What is the arithmetic relationship between the \$31.1 million tax reduction and the \$11.2 million credit in the deferral account? How can a tax credit be used in a deferral account? Why is the tax credit not simply included in forecast 2018 rates?

RESPONSE

- (a) As described in Part (b) below, the \$11.2 million credit proposed to be refunded through the CDNSADA is equivalent to the impact that the approved \$31.1 million tax deduction would have on the determination of the Company's 2018 Allowed Revenue. As explained in the Company's evidence at Exhibit D2, Tab 2, Schedule 1, the intent of the Company's Discontinuance of Site Restoration Cost Rider proposal, inclusive of the proposal to move the impact of the approved forecast tax deduction from rates (where it was originally forecast to reside) and into the CDNSADA for refund, is to serve a couple of purposes; a) it will effect a final true-up of actual versus approved Rider D amounts and impacts at the end of 2017 versus 2018, thus minimizing the amount of over-refund to be collected back from ratepayers, and b) it will ensure that the final true-up of the CDNSADA will result in a credit to customers, as opposed to having to recover the expected over-return amount of \$4 million which would be required without the proposed move of the tax deduct impact.
- (b) The \$11.2 million credit proposed to be refunded through the CDNSADA, as part of the Company's Discontinuance of Site Restoration Cost Rider proposal, is equivalent to the impact that the inclusion of a \$31.1 million tax deduction would have on the determination of the Company's 2018 allowed revenue, and reflects the grossed-up value of the tax deduction (\$31.1 million tax deduction * 26.5% tax rate / 73.5% reciprocal of the tax rate = \$11.2 million). The Company is proposing to refund the revenue requirement value of a tax deduction through the CDNSADA as opposed to rates, for the reasons described in part (a) above. Any deferral or variance account which has accounting or CRA permitted income tax deductibility results in related tax

Witnesses: A. Mandyam

Exhibit I.D2.EGDI.BOMA.32

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impacts being cleared through the associated total revenue requirement, just as is the case in this proposal.

Witnesses: A. Mandyam

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D2.EGDI.CME.1

Page 1 of 1

CME INTERROGATORY #1

INTERROGATORY

Ref: Exhibit D2, Tab 2, Schedule 1, page 3 of 5

At page 3, EGD states that "the Company has performed an analysis which shows that the actual Rider D amounts credited to ratepayers to date, plus the forecast amounts expected to be credited to ratepayers for the remainder of 2017, will result in a total of approximately \$383.8 million that will have been returned to ratepayers by the end of 2017."

CME wishes to better understand the analysis that the company performed. If the analysis is already part of the evidence, please provide a reference to where it can be found. If the analysis is not already part of the evidence, please provide it. If possible, CME would like EGD to provide an analysis that will quantify the impact of the individual drivers of the variance between the forecast amount and the actual amount returned, as well as the offsetting factors mentioned by EGD in paragraph 9 at page 3 of 5.

RESPONSE

See the response to APPrO Interrogatory #2, at I.D2.EGDI.APPrO.2and BOMA Interrogatory #31, at I.D2.EGDI.BOMA.31.

Witnesses: R. Cheung

A. Kacicnik R. Small

Filed: 2017-11-13 EB-2017-0086 Exhibit I.D2.EGDI.CME.2 Page 1 of 1

CME INTERROGATORY #2

INTERROGATORY

Ref: Exhibit D2, Tab 2, Schedule 1

Please confirm whether EGD will be pursuing Board approval for any other tax issues relating to the cancellation of Rider D in this application, aside from recording an \$11.2 million credit in the CDNSADA. For instance, whether EGD will calculate the tax consequences of returning \$4 million more to ratepayers over the period than the amount prescribed by the Board.

RESPONSE

The Company confirms that the only tax issue for which it seeks approval, in relation to the proposed discontinuance of the site restoration cost rider (Rider D), is to remove the 2018 forecast refund/Rider D tax deduct amount of \$31.1 million from the determination of 2018 Allowed Revenue, which results in an increase to allowed revenue of approximately \$11.2 million. As set out in the Company's proposal, Enbridge plans to refund a corresponding \$11.2 million to ratepayers as part of the disposition of the CDNSADA.

Witness: R. Small

Exhibit I.D2.EGDI.EP.10

Page 1 of 2

EP INTERROGATORY #10

<u>INTERROGATORY</u>

Reference: Exhibit D2 Tab 1 Schedule 1 Page 18

Preamble: The final balance in the 2017 CDNSADA will be transferred to the 2018 CDNSADA account. At present, the forecast 2017 ending balance is an approximate \$35 million debit/receivable, inclusive of an over refund versus the amount which was to be refunded through 2017, of approximately \$4.0 million in excess of the additional \$31.1 million that was expected to be refunded through Rider D during 2018.

- A). Please explain why a refund of \$31.1 million cannot continue during 2018 until there is a zero balance in the CDNSADA account.
- B). Please explain why this proposal is appropriate.

 With the plan to discontinue Rider D in 2018, there will be no monthly debit to the CDNSADA, with corresponding credit to accounts receivable, for the actual amounts refunded to customers through Rate Rider D. The impact of this will be to reduce the forecast over refund (or debit/receivable) of \$35.1 million

RESPONSE

A). At present the Company is forecasting that it will have actually refunded, through Rider D, approximately \$35 million more than was planned/approved to be refunded through the end of 2017 (\$383.8 million forecast versus \$348.7 approved through 2017), or approximately \$4 million more than was planned/approved to be refunded through the end of 2018 (\$383.8 million forecast versus \$379.8 approved through 2018). Therefore, if the refund of an additional \$31.1 million were to continue in 2018, and assuming volumes occur as forecast, the Company would have refunded a total of \$414.9 million versus a total approved amount of \$379.8 million, and would in turn have to seek recovery of approximately \$35 million from customers in 2019 through clearance of the CDNSADA. As a result, the Company believes it would be more appropriate to discontinue Rider D at the end of 2017, to avoid refunding further amounts in 2018 that would be in excess of the total Board approved amount of \$379.8 million (ie., limit the over refund to approximately \$4 million, versus it growing to approximately \$35 million), only to have to turn around and recover that amount from ratepayers in 2019, through clearance of the CDNSADA. The Company believes that such a scenario could cause ratepayer confusion.

Witnesses: A. Mandyam

Exhibit I.D2.EGDI.EP.10

Page 2 of 2

The response to part B) below further illustrates how continuing the refund / Rider D in 2018 would not draw the CDNSADA balance to zero.

- B). The balance in the CDNSADA, which reflects the cumulative variance between amounts approved for clearance and the actual amounts cleared, was derived through the cumulative impact of recording the following monthly entries or transactions:
 - To record the approved monthly net salvage refund amount to ratepayers, and to draw down the outstanding site restoration cost liability reflected in accumulated depreciation for rate base purposes

Debit: Other LT Liabilities (Accumulated Depreciation)

Credit: CDNSADA

2. To record the actual monthly net salvage refund amounts credited to customer bills

Debit: CDNSADA

Credit: Accounts receivable from customers

At the end of 2017, the amount which will be recorded through entry #1 to reflect the approved site restoration cost refund amount (credited to the CDNSADA) is \$348.7 million. However, the amount forecast to be recorded through entry #2 (debited to the CDNSADA), to reflect actual amounts refunded, is approximately \$383.8 million. Therefore, at the end of 2017 the Company forecasts a net debit/receivable balance in the CDNSADA of approximately \$35 million, which would reflect an over refund amount at that point in time.

Under the Company's proposal to discontinue Rider D at the end of 2017, entry #2 would not be required in 2018, but entry #1 would still be required in order to draw down the outstanding site restoration cost liability by the Board approved amount of \$379.8 million (thereby reflecting the approved impact on rate base). The recording of \$31.1 million through entry #1 throughout 2018, would therefore reduce the forecast 2017 over refund amount of \$35 million, to approximately \$4 million by the end of 2018.

Witnesses: A. Mandyam

Exhibit I.D2.EGDI.FRPO.19

Page 1 of 1

FRPO INTERROGATORY #19

INTERROGATORY

REF: Exhibit D2, Tab 2, Schedule 1

Preamble: We would like to better understand the credits calculated versus refunded during the IRM period to evaluate the EGD proposal.

Please place the approved credit and actual refund figures into a table by year.

- a) Please add an annual balance
- b) Please include any interest accrued to either ratepayers or the company
- c) Please provide the 2018/19 implications of either alternative as a forecast in the table if possible.

RESPONSE

- a) See the response to APPrO Interrogatory #2, at I.D2.EGDI.APPrO.2.
- b) As specified within the Board's EB-2012-0459 Decision and Accounting Order, as well as the Accounting Orders approved in each of EGD's 2015 to 2017 rate applications, no interest is to be calculated on the balance recorded in the CDNSADA. As such, no interest has been accrued on the life-to-date site restoration cost (Rider D) over refund recorded in the CDNSADA.
- c) See the response to APPrO Interrogatory #2, at I.D2.EGDI.APPrO.2.

Witnesses: R. Cheung

A. Kacicnik

Exhibit I.E1.EGDI.BOMA.33

Page 1 of 2

BOMA INTERROGATORY #33

INTERROGATORY

Ref: Exhibit E1, Tab 3, Schedule 1, p1

- (a) Please confirm that the actual "effective costs" of the 2017 debt issuances are the costs, if the debt has been issued, which are reflected in Table 1 on p1 of the Exhibit. If other numbers are used in Table 1, please explain the difference between the Board approved costs, and provide the actual costs of debt issued.
- (b) Are the terms (coupon rate excepted) of the forecast 2018 debt the same as the planned actual terms of the 2017 debt? Please describe any differences or likely differences.
- (c) When in November is the 2018 debt likely to be issued, or has it already been issued? If issued, what were the terms?
- (d) Please explain why the coupon rates of the 2018 ten and thirty year debt have been forecast to increase by forty-five and thirty-five basis points, respectively, over the updated forecast for 2017, ten and thirty year debt.
- (e) What is the current yield on the ten and thirty year Canadian government bonds (average of first week in November)?
- (f) Why is EGD proposing an increase of five basis points in the Corporate Spread over 2017 amounts?
- (g) Please confirm that assuming the forecast debt issuances for 2017 takes place, the actual rates will be reflected in Table 6, the updated forecast of Term Debt shown at Exhibit E2, Tab 1, Schedule 2, p1.

RESPONSE

(a) Table 1 of Exhibit E1, Tab 3, Schedule 1 includes the impact of the updated 2017 forecast debt issuance effective costs provided in this proceeding. As per the Board's EB-2012-0459 Decision and Rate Order, and as articulated in Appendix E of that Decision and Rate Order, the 2018 forecast cost of debt has been updated using the most current information available, including information on the actual amounts and rates associated with any debt issued in the prior year. As no actual 2017 debt

Witnesses: R. Craddock

Exhibit I.E1.EGDI.BOMA.33

Page 2 of 2

issuance had occurred at the time of filing (or as of yet), the Company used its most current forecast. The details of the updated forecast 2017 debt issuances and effective costs, including a comparison to the forecast issuances included in the 2017 Rate Application, EB-2016-0215, are provided in paragraph 4 and Table 2 of Exhibit E1, Tab 3, Schedule 1. Table 1 of Exhibit E1, Tab 3, Schedule 1 includes the actual effective costs of debt issued prior to 2017.

- (b) The coupon rate expected for the forecast 2018 issuance differs from the forecast for the 2017 issuance as the forecast for underlying Government of Canada long term bond rates increases from 2017 to 2018. In addition, expected corporate spreads are expected to increase marginally from 2017 to 2018.
- (c) The expected 2017 issuance date is late November to early December.
- (d) The increase in 2018 rates over 2017 rates is primarily attributable to anticipated increases in Government of Canada long term bond rates.
- (e) The current yield on Government of Canada 10 and 30 year Government bonds is 1.96% and 2.31%, respectively.
- (f) Corporate spreads are forecast using historical corporate spreads.
- (g) Given the Board's Procedural Order timelines for this proceeding, it would not be practical to incorporate any change from the current forecast assumptions.

Witnesses: R. Craddock

Exhibit I.E1.EGDI.BOMA.34

Page 1 of 1

BOMA INTERROGATORY #34

INTERROGATORY

Ref: Tab 1, Schedule 1, p2

What is the unamortized financial cost and why is it deducted from debt? How is it accounted for in regulatory and commercial financial statements?

RESPONSE

Unamortized financing costs, as shown in Exhibit E2, Tab 1, Schedule 1, page 2, refers to the value of term debt issuance costs, which are amortized over the term of the associated debt, which remain unamortized at a point in time (or from a utility capital structure perspective reflects the average of monthly averages unamortized issuance cost balance). Debt issuance costs which are amortized over the term of the associated debt can include: commissions, legal fees, debt premiums or discounts, and interest rate hedge / swap unwind costs.

From a regulatory financial statement perspective, debt issuance costs are included in the calculation of the effective rate of each term debt issue, which is then used within the capital structure calculation to derive the LTD interest component of the cost of capital. As issuance costs are captured within the effective rate applied to LTD, the amortization of those costs for financial accounting purposes is eliminated in the determination of utility income. In the determination of the utility LTD capital structure component, unamortized issuance costs are deducted from the LTD principal balance to reflect the proceeds provided by the LTD debt issuances.

From a financial accounting perspective, debt issuance costs are recognized on the balance sheet at the time of issuance. The issuance costs are then amortized / expensed from the balance sheet to the income statement over the life of the associated debt.

Witness: R. Small

Exhibit I.E1.EGDI.EP.11

Page 1 of 1

EP INTERROGATORY #11

INTERROGATORY

Reference: Exhibit E1 Tab 2 Schedule 1

Preamble: In its EB-2012-0459 Decision with Reasons issued July 17, 2014, the Board determined that "the Cost of Capital will be re-set each year using the Board's established approach" (p.10). The Board further concluded that "the allowed ROE for purposes of calculating the ESM should be the ROE used to determine the allowed revenue requirement" (p.14) and that "[T]he preferred approach is to update the return on equity each year during the annual rate adjustment proceeding using the Board-approved parameters.

- A). Please provide a schedule that shows for each year, including the base year and forecast for 2018, the Allowed ROE and Actual ROE under the CIR Plan. For each year show the actual (or forecast) ESM amounts paid to ratepayers.
- B). Please show the annual and total net ROE to EGD over CIR period (including 2018F). Monetize this return. Show the Total Allowed Average ROE over the CIR period and monetize this return.
- C.) Show the total ESM amounts paid to ratepayers (including 2018F)

RESPONSE

The information requested is not relevant to the Company's update of the 2018 Allowed Revenue as outlined in the elements to be updated in the annual Custom Incentive Rate Process evidence filed at Exhibit A, Tab 3, Schedule 1, Appendix A.

EGD's past actual utility results, including actual ROE and allowed ROE, and any resulting earnings sharing amounts approved by the Board for payment to ratepayers has been provided for each of the fiscal years 2014 through 2016 in past annual ESM and deferral and variance account review applications. Future actual utility results for 2017 and 2018 will be provided in future similar applications.

Witnesses: A. Patel

Exhibit I.E1.EGDI.VECC.5

Page 1 of 1

VECC INTERROGATORY #5

<u>INTERROGATORY</u>

Reference: Exhibit E1/T3/S1/pg.2

- a) Have the two \$150 debt issuances listed in Table 2 been executed? If yes please confirm the effective costs remain as per Table 2.
- b) What was the Canada 10 and 30 yield in August when the original issuances were planned?
- c) What were the reasons for delaying the debt issuances?
- d) The current Canada 10 year yield as of October 31 was 2.30% (http://www.bankofcanada.ca/rates/interest-rates/canadian-bonds/)
- e) Please explain how the 2.40% for Canada Long-term was established.

<u>RESPONSE</u>

- a) The 2017 debt issuance has not occurred as of yet.
- b) The Canada 10 and 30 yield was 1.88% and 2.29%, respectively, in August 2017.
- c) At the time of the planned debt issuances were to be completed, management was in the process of assessing the potential of filing an application under the MAAD's framework to pursue the amalgamation of EGD and Union Gas. The decision to proceed was targeted for November and therefore management felt it was prudent to defer issuances until the Market was able to digest the plan..
- d) The yield of 2.30% on October 31 is in reference to 30 year Government of Canada bonds.
- e) The forecast for Canada long term rates is based on a survey of financial institutions.

Witnesses: R. Craddock

Filed: 2017-11-13 EB-2017-0086 Exhibit I.E1.EGDI.VECC.6 Page 1 of 1 Plus Attachment

VECC INTERROGATORY #6

INTERROGATORY

Reference: Exhibit E1/T3/S1/pg.2

- a) Please provide the source of the Canada yield 10 and 30 year forecast for the August 2018 debt issuances.
- b) Please explain the reason for the increase in the corporate spread as between November 2017 and August 2018.
- c) What would be impact on the revenue requirement if the August 2018 issuances had the same effective costs as the November 2017 issuances?

RESPONSE

- a) The Canada yield forecast is based on a survey of financial institutions.
- b) The forecast corporate spread is based on historical corporate spreads.
- c) If the forecast August 2018 issuances were assumed to have the same effective rates (and coupon rates) as the forecast November 2017 issuances, it would result in a \$0.5 million reduction to Allowed Revenue and gross deficiency. To illustrate the change, Attachment #1 reproduces Exhibit E2, Tab 1, Schedules 1 and 2, under the assumption that the forecast August 2018 issuances have the same effective rates as the forecast November 2017 issuances.

Witnesses: R. Craddock

Filed: 2017-11-13 EB-2017-0086 Exhibit I.E1.EGDI.VECC.6 Attachment Page 1 of 3

COST OF CAPITAL 2018 UPDATED FORECAST

Col. 1 Col. 2 Col. 3 Col. 4

Line No.		Principal Excl. CC/CIS	Component	Cost Rate	Return Component
		(\$Millions)	%	%	%
1.	Long and Medium-Term Debt	3,858.2	61.84	4.70	2.906
2.	Short-Term Debt	34.8	0.56	1.60	0.009
3.		3,893.0	62.40		2.915
4.	Preference Shares	100.0	1.60	2.72	0.044
5.	Common Equity	2,246.1	36.00	8.84	3.182
6.		6,239.1	100.00		6.141
7.	Rate Base	(\$Millions)			6,239.1
8.	Utility Income	(\$Millions)			323.6
9.	Indicated Rate of Return				5.187
10.	Deficiency in Rate of Return				(0.954)
11.	Net Deficiency	(\$Millions)			(59.5)
12.	Gross Deficiency	(\$Millions)	(other than CC	- CIS)	(81.0)
13.	Customer Care/CIS Deficiency	(\$Millions)	(\$131.1 vs \$126	6.6)	(4.5)
14.	Total Gross Revenue Deficiency	(\$Millions)			(85.5)
15.	Revenue at Existing Rates	(\$Millions)			2,896.2
16.	Allowed Revenue	(\$Millions)			2,981.7
17.	Gross Revenue Deficiency	(\$Millions)			(85.5)

Filed: 2017-11-13

EB-2017-0086

Exhibit I.E1.EGDI.VECC.6

Attachment Page 2 of 3

CALCULATION OF COST RATES FOR CAPITAL STRUCTURE COMPONENTS 2018 UPDATED FORECAST

		Col. 1	Col. 2	Col. 3
Line No.		Average of Monthly Averages		Carrying Cost
	Long and Medium-Term Debt	(\$Millions)		(\$Millions)
1. 2. 3.	Debt Summary Unamortized Finance Costs (Profit)/Loss on Redemption	3,888.1 (29.9)		182.7 -
4.		3,858.2		182.7
5.	Calculated Cost Rate	=	4.70%	:
	Short-Term Debt			
6.	Calculated Cost Rate	=	1.60%	:
	Preference Shares			
7. 8. 9.	Preference Share Summary Unamortized Finance Costs (Profit)/Loss on Redemption	100.0 - 		2.7 - -
10.		100.0		2.7
11.	Calculated Cost Rate	=	2.72%	:
	Common Equity			
12.	Board Formula ROE	_	8.84%	_

Exhibit I.E1.EGDI.VECC.6

Attachment Page 3 of 3

SUMMARY STATEMENT OF PRINCIPAL AND CARRYING COST OF TERM DEBT 2018 UPDATED FORECAST

			Col. 1	Col. 2	Col. 3
			COI. 1	OOI. 2	001. 3
			Average of		
Line	Coupon		Monthly Averages	Effective	Carrying
No.	Rate	Maturity Date	Principal	Cost Rate	Cost
,			(\$Millions)		(\$Millions)
Mediu	m Term No	otes	(, ,		,
1.	8.85%	October 2, 2025	20.0	8.970%	1.8
2.	7.60%	October 29, 2026	100.0	8.086%	8.1
3.	6.65%	November 3, 2027	100.0	6.711%	6.7
4.	6.10%	May 19, 2028	100.0	6.161%	6.2
5.	6.05%	July 5, 2023	100.0	6.383%	6.4
6.	6.90%	November 15, 2032	150.0	6.950%	10.4
7.	6.16%	December 16, 2033	150.0	6.180%	9.3
8.	5.21%	February 25, 2036	300.0	5.183%	15.5
9.	4.77%	December 17, 2021	175.0	5.310%	9.3
10.	4.04%	November 23, 2020	200.0	5.209%	10.4
11.	4.95%	November 22, 2050	200.0	4.990%	10.0
12.	4.95%	November 22, 2050	100.0	4.731%	4.7
13.	4.04%	November 23, 2020	200.0	2.801%	5.6
14.	4.50%	November 23, 2043	200.0	4.198%	8.4
15.	3.15%	August 22, 2024	215.0	3.241%	7.0
16.	4.00%	August 22, 2044	215.0	3.889%	8.4
17.	4.00%	August 22, 2044	170.0	4.436%	7.5
18.	3.31%	September 11, 2025	400.0	3.619%	14.5
19.	2.50%	August 5, 2026	300.0	3.423%	10.3
20.	2.90%	November 1, 2027	150.0	2.952%	4.4
21.	3.80%	November 1, 2047	150.0	3.821%	5.7
22.	2.90%	August 15, 2028	56.3	2.952%	1.7
23.	3.80%	August 15, 2048	56.3	3.821%	2.2
24.			3,807.6		174.5
Long-	Term Debe	entures			
٥٦	0.050/	D	05.0	0.0100/	0.4
25.	9.85%	December 2, 2024	85.0	9.910%	8.4
26.			85.0		8.4
27.	Removal	of separately treated CIS			
	64% assu	umed debt of 2018 \$7.0M			
	rate base	value	(4.5)	5.350%	(0.2)
00	TakalT	Dalet	2.000.4		100 7
28.	Total Teri	т рерт	3,888.1		182.7

Exhibit I.G1.EGDI.STAFF.16

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BOARD STAFF INTERROGATORY #16

<u>INTERROGATORY</u>

Ref: Cost Allocation Exhibit G1 / Tab 1 / Schedule 1 / p. 4 Exhibit G2 / Tab 1 / Schedule 1 / p. 3

Question(s):

- a) Please confirm that the cost allocation methodology for Rate 332 and the Dawn Transportation Service was previously approved by the OEB. Please confirm that the same cost allocation methodology was used and approved by the OEB in Enbridge's 2017 Rates proceeding (EB-2016-0215).
- b) Please explain the minor variance between the \$2,983.55 million figure cited in Table 1 (Exhibit G2 / Tab 1 / Schedule 1 / p. 3) and the proposed 2018 allowed revenue amount of \$2,982.2 million.

RESPONSE

a) The Company confirms that the same cost allocation methodology was used and approved by the Board for Rate 332 service and Dawn Transportation Service ("DTS") in Enbridge's 2017 Rate Proceeding (EB-2016-0215).

The Company further confirms that the cost allocation methodology for Rate 332 was initially approved by the Board in the GTA Project Decision and Order (EB-2012-0451) where the Board determined that 60% of the annual revenue requirement for Segment A will be recovered from Rate 332 shippers through a contract demand charge for contracted capacity.

The Company also confirms that the cost allocation methodology for DTS was initially approved by the Board as part of the Dawn Access Settlement Agreement (EB-2014-0323).

b) The minor difference between \$2,983.55 million (Exhibit G2, Tab 1, Schedule 1, page 3, Table 1) and the proposed 2018 allowed revenue amount of \$2,982.2 million (Exhibit F1, Tab 1, Schedule 1, page 3, Column 3, Line 9) is due to the inclusion of DPAC revenue and cost of approximately \$1.42 million respectively in Table 1.

Witnesses: A. Kacicnik

B. So

Filed: 2017-11-13 EB-2017-0086 Exhibit I.G1.EGDI.FRPO.20 Page 1 of 1

FRPO INTERROGATORY #20

INTERROGATORY

REF: Exhibit G1, Tab 1, Schedule 1, page 4

Preamble: We would like to understand better the cost recovery for Segment A of the GTA Reinforcement Project.

Please provide the peak day utilization of Segment A in terms of the GJ/day between Transportation by Others and Utility Peak Day requirements.

<u>RESPONSE</u>

Segment A has a peak day capacity of 2,000,000 GJ/day, where 60% (1,200,000 GJ/day) is utilized by Rate 332 transportation service customers and 40% (800,000 GJ/day) is utilized by the utility's / Company's bundled customers.

Witnesses: A. Kacicnik

B. So

Filed: 2017-11-13 EB-2017-0086 Exhibit I.G1.EGDI.FRPO.21

Page 1 of 1

FRPO INTERROGATORY #21

INTERROGATORY

REF: Exhibit G1, Tab 1, Schedule 1, page 4

Preamble: We would like to understand better the cost recovery for Segment A of the GTA Reinforcement Project.

Please provide the components of Revenue requirement that contribute to the recovery of Segment A.

a) Who is at risk for the recovery of under-utilized capacity on Segment A?

RESPONSE

The forecast annual revenue requirement for Segment A consists of interest and return on rate base, income tax, depreciation expense, municipal tax, and operating and maintenance expense.

The revenue requirement for Segment A is forecast to be recovered through Contract Demand ("CD") charges for shippers under Rate 332 transportation service (60% of Segment A revenue requirement) and through volumetric charges for EGD's bundled customers (40% of Segment A revenue requirement).

The Company is at risk for full recovery of Segment A revenue requirement if actual CD charges and / or actual volumes end up being lower than the forecast CD and / or forecast volumes.

Witnesses: A. Kacicnik

B. So

Filed: 2017-11-13 EB-2017-0086 Exhibit I.G1.EGDI.FRPO.22 Page 1 of 1

FRPO INTERROGATORY #22

<u>INTERROGATORY</u>

REF: Exhibit G1, Tab 1, Schedule 1, page 4

Preamble: We would like to understand better the cost recovery for Segment A of the GTA Reinforcement Project.

Please describe initiatives planned, undertaken or implemented to use excess capacity beyond the Transportation by Others and Utility Peak Day needs.

<u>RESPONSE</u>

Currently, Segment A pipeline capacity is fully subscribed between Rate 332 and EGD.

The 2017 / 18 winter will be the first full opportunity of the Company to assess the utilization of Segment A integrated in with EGD's overall network and associated interconnects. EGD intends to review overall system performance and flows after this winter to determine any availability of excess capacity. Following this review, EGD will consult with existing shippers and interested parties to discuss available excess capacity and determine interest on potential usage of excess capacity through means such as IT or TS services.

Witnesses: A. Kacicnik

B. So.

Filed: 2017-11-13 EB-2017-0086 Exhibit I.H1.EGDI.STAFF.17 Page 1 of 2

BOARD STAFF INTERROGATORY #17

<u>INTERROGATORY</u>

Ref: Interruptible Service Program Exhibit H1 / Tab 2 / Schedule 1

Preamble:

Enbridge provided a summary of the issues discussed at the July 2017 customer consultation on the Interruptible Service Program. Enbridge also provided its response to each issue.

Question(s):

a) For the issues where Enbridge has noted further review is required, please provide a discussion of the expected next steps.

RESPONSE

Updates to suggestion items identified for further review:

Suggested item 2 [Provide notifications when Curtailment Probability Status changes via email or text] - Text notifications are currently not available. Currently, customers can receive email notifications when the curtailment status is changed to High. However, setting up an email notification for a customer involves a manual process by Enbridge following a customer's request to be added to a list to receive email notifications when the curtailment status is changed to High. Further investigation is being done on whether an online service called MyAccount could be utilized to send (email or text) notification to customers when the Operational Status has changed. However, the timing of this feature will not be in scope until mid to late 2018 based on Enbridge's web designs resource prioritization.

Suggested item 3 [End curtailment in the afternoon after the morning lift instead of continuing for the entire gas day] - After further review, the flexibility of this request is limited as curtailment is typically based on the gas day which aligns with gas contracts and IT systems. Any deviation from this will require EGD to manually calculate the total consumption and update the system for each account. Based on the timing and

Witness: R. DiMaria

Filed: 2017-11-13 EB-2017-0086 Exhibit I.H1.EGDI.STAFF.17 Page 2 of 2

circumstances (CDS allowance, distribution system operations & weather conditions) of the curtailment Enbridge may/could end the curtailment prior to the end of a Gas Day.

Suggested item 7 [Increase the interruptible notification period for rate 170 from 4 hours] - An internal review is needed to determine whether there is value and viability to introducing a tiered interruptible rate option. If so, suggestions will be shared with customers at the next customer stakeholder meeting.

Witness: R. DiMaria

Exhibit I.H1.EGDI.EP.12

Page 1 of 1

EP INTERROGATORY #12

INTERROGATORY

Reference: Exhibit H1Tab 1Schedule 1Table 1; Exhibit H2 Tab 7 Schedule1

Preamble: For the typical residential customer, the proposed rate impact translates / results in an increase of approximately \$29 annually excluding Cap and Trade charges.

- A). Please provide the annual Rate impacts for the same residential customer since the CIR base year. Provide Total and average.
- B). Please monetize the total rate increase and the average per year.

RESPONSE

a) and b)

The table below provides the 2014 to 2017 Board-approved and 2018 proposed typical residential annual rate and \$ bill impacts. The impacts are expressed on a T-Service basis (i.e., total bill excluding gas costs and Cap and Trade charges). Also provided in the table are the 5 year average rate and \$ bill impacts.

<u>Year</u>	Rate 1 T- Service Rate Impact	Rate 1 T- Service Bill Impact
2014	-3.5%	(\$19)
2015	1.8%	\$9
2016	5.1%	\$29
2017	1.2%	\$7
Proposed 2018	4.8%	\$29
5 Year Average	1.9%	\$11

Witnesses: J. Collier

A. Kacicnik

Filed: 2017-11-13 EB-2017-0086 Exhibit I.H1.EGDI.FRPO.23

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FRPO INTERROGATORY #23

INTERROGATORY

REF: Exhibit H1, Tab 2, Schedule 1

Preamble: We would like to understand better the opportunities available to mitigate peak day driven costs through the use of Interruptible Contracting.

Did EGD invite or survey all types of contract customers including firm? If not, why not?

- a) Did EGD invite customers who migrated from Interruptible to Firm in the last 5-10 years? If not, why not?
- b) Did EGD ask what level of incentive would customers need to move from Firm to Interruptible?
 - i) If not, what are EGD's views on an appropriate approach to determining an appropriate economic incentive offered to customers to migrate to interruptible status to avoid future builds?
- c) Does EGD see any potential in assessing these incentives in the context of the Carbon Cap & Trade regime? Please explain how the economics of these incentives could be improved for customers and/or the company.

RESPONSE

- a) The intent of the consultative was to gather feedback from current interruptible customers from their experience based on the current interruptible program. Once that information has been reviewed and Enbridge has evaluated whether it can accommodate the suggestions received, then those suggestions will be shared at the next annual general large volume customer meetings (in each of the Company's franchise regions), which are attended by both firm and interruptible customers.
- b) No. The current curtailment credits are appropriately set. In most years, with the exception of 2013/2014 winter, customers would financially benefit from being on an interruptible rate.

Witness: R. DiMaria

Filed: 2017-11-13 EB-2017-0086 Exhibit I.H1.EGDI.FRPO.23

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i) The Curtailment Program is currently operating well with a high compliance rate of 96%. Interruptible services are available to customers who can accommodate the total interruption of gas service when required by the Company through either a complete shutdown of operations or the ability and readiness to switch to an alternative fuel source.

Customers that have migrated in the past from interruptible service to firm service did so due to issues with complying with curtailment and/or did not like the uncertainty of the potential frequency of curtailment. The character of interruptible service and the issues explained in Exhibit H1-2-1, page 3, compel customers to sensibly and comprehensively evaluate the appropriateness of the curtailment program for their business.

c) It is not clear that there would be any impacts to customers from Cap and Trade as Cap and Trade costs are determined on a per unit usage basis. Cap and Trade charges apply / are charged on customers' actual usage as per the Cap and Trade regulation.

Witness: R. DiMaria

Exhibit I.H2.EGDI.STAFF.18

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BOARD STAFF INTERROGATORY #18

INTERROGATORY

Ref: Rate Handbook

Exhibit H2 / Tab 6 / Schedule 1

Question(s):

a) The energy content information does not seem to be properly reflected in the Rate Handbook. Please confirm that the Rate Handbook will be updated as part of the Draft Rate Order process to show the energy content.

RESPONSE

Confirmed. Due to a formatting error, the updated heat content of 38.42 MJ/m3 did not display properly in the print version of the Rate Handbook. The updated energy content will be properly displayed in the Draft Rate Order.

Witness: J. Collier