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January 28, 2014

VIA RESS, EMAIL and COURIER

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

Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Undertakings - Technical Conference - Outstanding Responses

Attached please find the outstanding responses to undertakings given to Enbridge during the course of the Technical Conference which took place January 17, 18, and 20, as follows:

Exhibit TCU 1.8;
Exhibit TCU1.11;
Exhibit TCU1.13;
Exhibit TCU2.1;
Exhibit TCU2.4;
Exhibit TCU2.5;
Exhibit TCU2.9; and
Exhibit TCU3.21.

Also attached is the corrected undertaking, Exhibit TCU2.15.

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

Yours truly,

(original signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

UNDERTAKING TCU1.8

UNDERTAKING

Technical Conference, TR 45

EGDI to provide a response to SEC technical conference question SEC - 3 and restate the table, including correcting the accounting error referred to.

RESPONSE

See response below

SEC Technical Conference Question 3

Ref: I.A1.EGDI.STAFF.4 Page 2

Please restate the table including the impacts of correcting the accounting error referred to.

Enbridge provides the following response:

The 2010 through 2012 results, provided in the table in response to Board Staff Interrogatory #4 found at Exhibit I.A1.EGDI.STAFF.4, have been updated below to account for the impacts of the accounting error.

Witnesses: K. Culbert
R. Small

Fiscal Year		Board Approved ROE	Before Earnings Sharing: Normalized Actual ROE	Before Earnings Sharing: Actual ROE	After Earnings Sharing: Normalized Actual ROE	After Earnings Sharing: Actual ROE
		%	%	%	%	%
2000		9.730%	10.829%	8.229%	(a)	(a)
2001		9.540%	10.029%	10.800%	"	"
2002		9.660%	11.805%	8.982%	"	"
2003		9.690%	9.743%	13.140%	"	"
2004		9.690%	10.828%	12.342%	10.660%	12.165%
2005		9.570%	10.343%	10.343%	(a)	(a)
2006		8.740%	10.343%	7.200%	"	"
2007		8.390%	10.722%	11.639%	"	"
2008		8.660%	10.208%	11.867%	9.936%	11.586%
2009		8.310%	11.203%	12.361%	10.261%	11.422%
2010	(c)	8.370%	10.071%	9.255%	9.211%	8.387%
2011	(c)	7.940%	8.908%	8.972%	8.181%	8.253%
2012	(c)	7.520%	7.628%	6.061%	7.250%	5.689%
2013	(b)	8.930%	-	-	-	-

(a) There was no earnings sharing mechanism in these years, therefore ROE results are the same as in the before earnings sharing columns.

(b) The Company is not in a position to provide an estimate of 2013 results.

(c) These are actual and normalized ROE's which have taken account of the impact of the accounting error identified in EGDI's September 30, 2013 financial results.

Witnesses: K. Culbert
R. Small

UNDERTAKING TCU1.11

UNDERTAKING

TR Technical Conference, page 99

EGDI [Concentric] to provide the sum of capital costs plus OM&A costs for each company in the sample and for the industry as a whole (the twenty five companies) and for Enbridge, and divide by total customers for 2010 and 2011.

RESPONSE

Preliminary comments:

Using TFP-based costs[1] per customer for a single year (e.g., 2010 or 2011) to benchmark the performance of individual distributors or groups of distributors is inappropriate for the same reasons that using the growth in TFP indexes for a single year to measure the productivity of individual distributors or groups of distributors is inappropriate. To account for year-to-year volatility in the components of a TFP index, it is widely accepted that TFP results must be evaluated over a sufficiently long period, such as ten years, to identify long term trends in productivity.

In addition, it is common practice to benchmark distributors according to measures of costs per customer and costs per volume of gas delivered to customers. In fact, measures of costs per volume may be the better approach to benchmark distributors because costs per volume provides a broader view of aggregate costs in relation to total sales and transport volumes not captured on a per customer basis.

Lastly, TFP-based costs for any distributor in any year are not the same as the revenue requirement for that distributor in that year[2], mainly because TFP-based capital costs

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[1] As used in this response, "TFP-based costs" are the costs that were calculated for Concentric's TFP analysis, Exhibit A2, Tab 9, Schedule 1, Pages 95 – 123.

[2] TFP-based total costs is calculated as the sum of TFP capital costs, labour, and materials. TFP-based capital costs are a calculated value; capital costs are not reported in a distributor's annual regulatory filing. TFP-based capital costs are the product of TFP-based price of capital and capital quantity. The price of capital is a calculation that includes terms for the cost of capital, depreciation, and capital gains. The capital quantity is also a calculation, based on estimates of the value in constant (real) dollars of each vintage of in-service plant. For Concentric's TFP analysis, TFP-based labour and materials costs for a year are the O&M expenses as reported in a distributor's annual regulatory filing; the sum of TFP-based labour and materials costs is distribution, transmission, and storage O&M expenses, net of pensions and benefits expense. However,

account for economic costs, such as capital gains, that are not reflected in regulatory accounting revenue requirement calculations. Annual bond yields and ROEs that serve as proxies for the cost of capital also vary from those allowed in rates for individual companies.

Total Factor Productivity is measured with an index designed to capture the trends in inputs and outputs for a given company or industry. The assumptions required to estimate total costs, especially for capital, are not designed to determine an absolute measure of cost in a given year. The overall level of TFP-based costs and year-to-year differences in TFP-based costs are significantly impacted by all of these factors. These data must therefore be considered in light of these limitations.

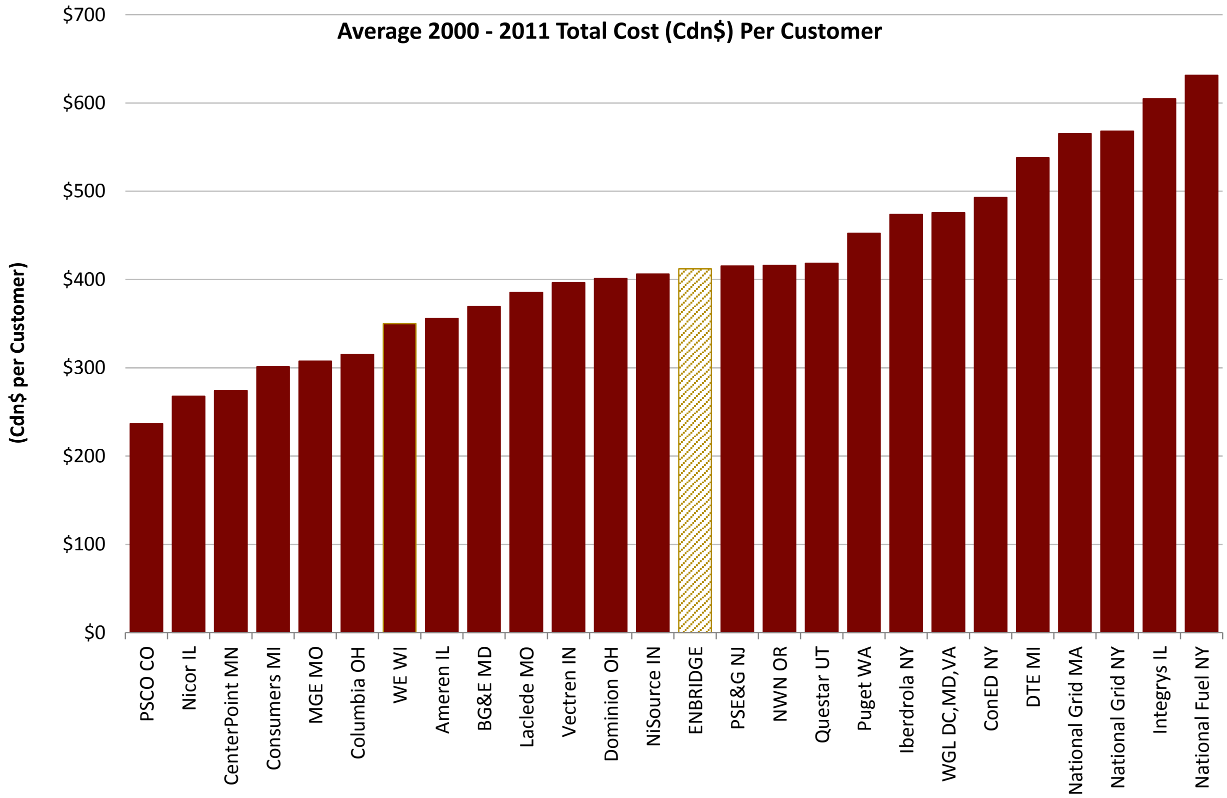
For these reasons, TFP-based costs have been provided for this response for the entire period of Concentric's TFP analysis, 2000 to 2011, and the benchmarking results are expressed as average costs per volume and costs per customer for Enbridge, the 25 Company Industry Study Group, and the seven company Sub-Group for 2000 to 2011.

Analysis and Discussion

The sum of TFP-based capital costs plus OM&A costs, divided by total customers for each of the 25 companies in the sample plus Enbridge, for the study period, 2000 to 2011 is provided in Attachment TCU1.11 page 1; cost data per volume (103m3) is provided in Attachment TCU1.11 page 2.

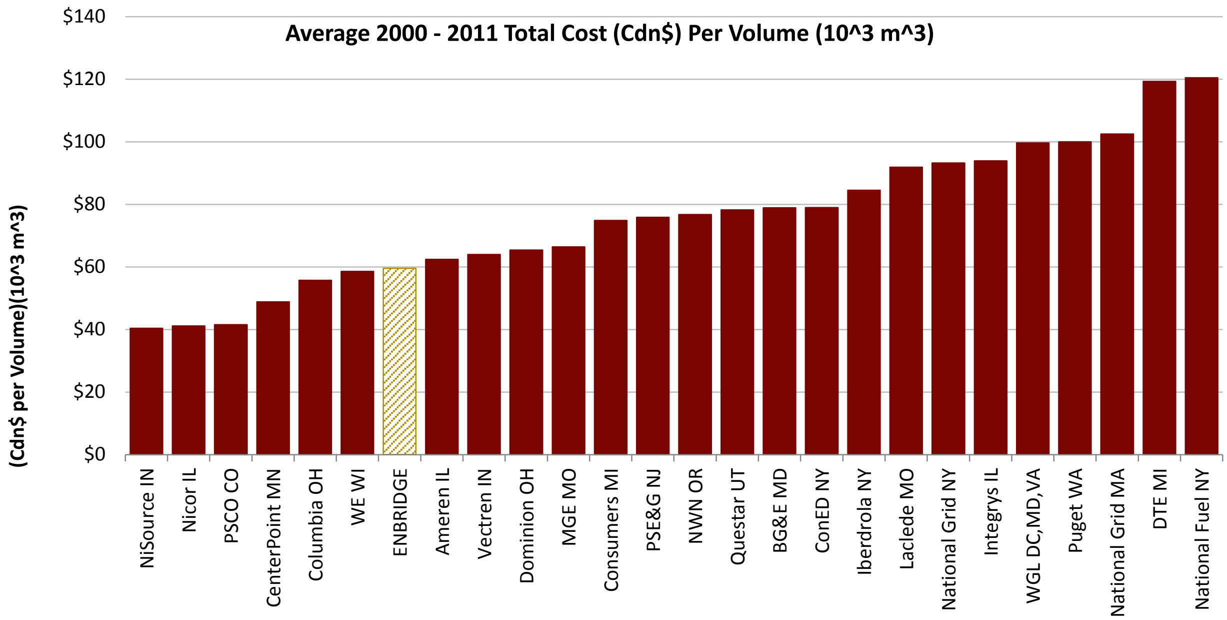
The following Figure 1, Cost per Customer benchmarking analysis, summarizes the average 2000 to 2011 cost per customer results in Attachment TCU1.11 page 1. Figure 1 indicates that Enbridge's average 2000 to 2011 average TFP-based cost is at the median for the 26 companies.

Figure 1 Benchmarking Analysis: Average Total TFP-based Cost per Customer



The following Figure 2, Cost per Volume benchmarking analysis, summarizes the average 2000 to 2011 cost per volume results in Attachment TCU1.11 page 2. Figure 2 indicates that Enbridge's average 2000 to 2011 average TFP-based cost is at the separation point between the top and second quartiles for the 26 companies.

Figure 2 Benchmarking Analysis: Average Total TFP-based Cost per Volume (10^3m^3)



The following Figure 3 provides a summary of TFP-based total costs per customer for the 25 company group, the 7 company group and Enbridge for the 2000 to 2011 study period; Figure 4 provides a summary of TFP-based total costs per volume for the 25 company group, the 7 company group and Enbridge for the 2000 to 2011 study period.

Figure 3 Total TFP-based Cost (Cdn$) Per Customer

	Total Cost (Cdn$) Per Customer		
	Industry Study Group	Seven Company Sub-Group	EGD
2000	503	483	416
2001	521	484	364
2002	521	495	463
2003	469	453	442
2004	384	366	357
2005	304	284	381
2006	283	260	412
2007	321	291	351
2008	350	315	374
2009	498	460	406
2010	459	426	463
2011	388	360	515
Average Annual Cost Per Customer			
2000-2011	417	390	412

Figure 4 Total TFP-based Cost (Cdn$) Per Volume (10^3m^3)

	Total Cost (Cdn$) Per Volume (10^3 m^3)		
	Industry Study Group	Seven Company Sub-Group	EGD
2000	78.43	75.88	52.70
2001	91.36	83.91	47.11
2002	89.38	83.88	64.39
2003	81.05	79.01	56.63
2004	71.43	69.54	48.88
2005	57.72	55.88	54.02
2006	57.42	53.33	63.99
2007	61.16	55.45	53.07
2008	66.01	60.24	57.84
2009	98.54	90.22	63.63
2010	91.04	79.43	73.08
2011	74.95	66.20	79.07
Average Annual Cost Per Volume (10^3 m^3)			
2000-2011	76.54	71.08	59.53

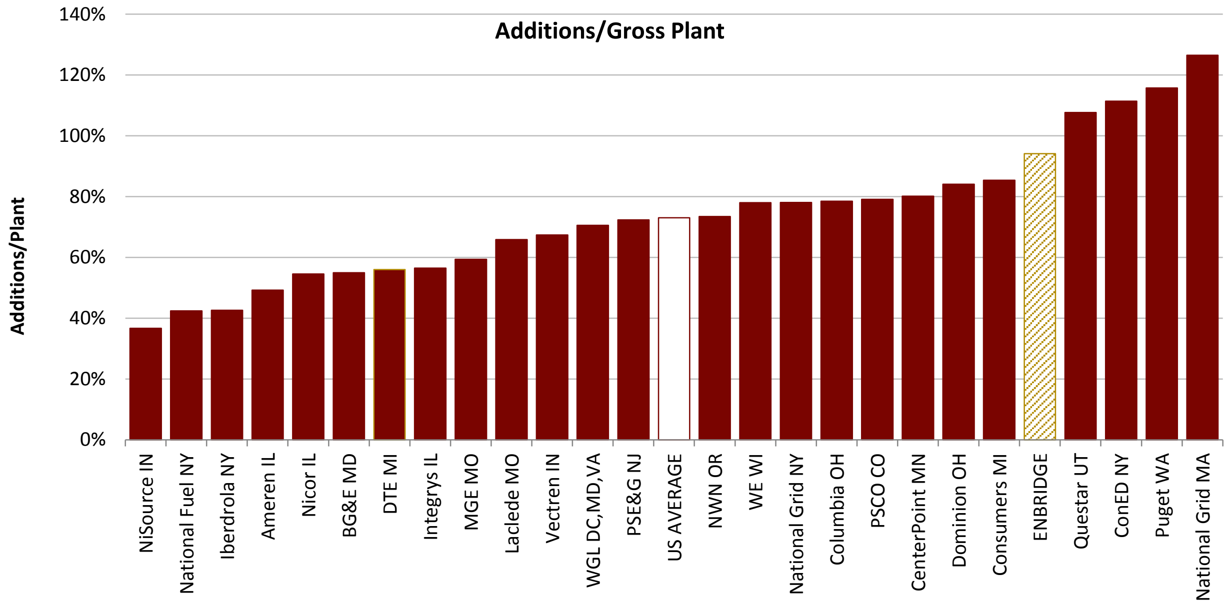
Explanation

The Concentric Incentive Ratemaking Report demonstrates that EGD’s 2011 O&M costs per customer and O&M costs per unit of volume are within the lowest – best – quartile, and that the gap between average O&M costs per customer and O&M costs per unit of volume for the study group grew steadily between 2000 and 2011. (Exhibit A2, Tab 9, Schedule 1, pp. 84 to 86.)

The Concentric Incentive Ratemaking Report also demonstrates that EGD’s 2011 Net Plant per customer and Net Plant per unit of volume are in the highest and third highest quartiles, respectively, but that the gap between average Net Plant per customer and Net Plant per unit of volume for the study group has been narrowing between 2000 and 2011. (Exhibit A2, Tab 9, Schedule 1, pp. 81 to 83.)

Thus, Enbridge ranks higher (better) on (a) O&M per customer and volume benchmarking than on (b) TFP-based total cost per customer and volume benchmarking because of the effect of Enbridge’s capital cost per customer and volume on total cost per customer and volume. As demonstrated by Figure 5, below, only four companies in the study group added plant in recent years at a greater rate than Enbridge.

Figure 5 2001 – 2011 Plant additions as a Percent of 2000 Plant



During the 2001 to 2011 period a large component of plant additions for these 26 companies was (a) replacement of leak-prone pipe[3] and (b) new meters, services, and main extensions to serve new customers. Enbridge's high rate of plant additions is well-understood; Enbridge has been replacing leak prone pipe at a greater rate than other distributors and Enbridge has been adding customers at a greater rate than other distributors.

Specifically, since 2001, Enbridge has replaced approximately 1,000 km of leak-prone pipe; currently, virtually none of Enbridge distribution mains is leak prone. In contrast, most US distributors, including the study group companies, have been replacing leak prone pipe at a slower rate.[4] Also, Enbridge's 2001 to 2011 customer growth rate, 2.6%, was higher than all other companies in the industry study group.

[3] Leak-prone pipe generally includes cast iron, wrought iron and non-cathodically-protected steel mains and services.

[4] Related to this point, gas distribution cost models often include a measure of leak prone main in miles as a percent of total distribution mains, to reflect the effect of leak prone pipe on leak repair expense. However, gas distribution cost models should also include a measure to account for the accelerated replacement of leak prone pipe. Other things being equal, a gas distributor that has replaced its leak prone pipe at an accelerated rate will have greater additions to plant in recent years, and therefore higher total costs per customer than distributors that have significant leak prone pipe remaining to be replaced. Similarly, a gas distributor that does not have much leak prone pipe because it recently completed replacing its accelerated leak-prone pipe replacement program will have greater additions to plant in recent years and higher total costs per customer than a gas distributor that has never had much leak prone pipe.

In summary, Enbridge's TFP-based total cost rank must be considered against the limitations of using a TFP index, designed to compare trends in inputs/outputs for the purposes of absolute dollar comparisons. One must also consider company specific circumstances (e.g., accelerated leak prone pipe replacement) that drive capital investment levels.

Total Cost (Cdn$) Per Customer

Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	Average 2000 - 2011
PSCO CO	297.41	328.97	317.21	285.78	206.09	145.70	134.94	168.62	179.72	285.85	268.44	221.19	236.66
Nicor IL	314.64	323.29	331.60	297.31	248.74	183.16	178.16	203.37	233.52	339.89	312.22	248.53	267.87
CenterPoint MN	329.75	345.77	343.98	312.74	248.91	203.17	187.27	221.69	237.36	320.55	283.08	255.16	274.12
Consumers MI	312.59	342.75	376.84	337.81	288.59	239.06	201.49	232.59	255.11	376.66	346.94	303.65	301.17
MGE MO	322.73	369.14	344.20	337.99	281.40	202.47	195.38	245.25	283.10	402.79	379.98	327.10	307.63
Columbia OH	430.98	388.52	321.49	292.30	252.67	223.95	232.77	267.66	297.55	416.89	372.76	284.46	315.17
WE WI	429.82	423.02	442.76	388.16	315.30	235.06	235.33	255.27	304.78	415.36	410.64	344.23	349.98
Ameren IL	428.38	451.98	464.80	403.70	318.44	233.38	254.25	282.04	311.01	429.11	382.34	311.38	355.90
BG&E MD	440.94	442.42	445.28	387.55	346.49	275.67	273.13	307.98	317.39	444.48	400.79	348.61	369.23
Laclede MO	409.57	455.12	466.54	426.88	356.36	285.47	277.02	310.66	348.41	485.58	436.70	365.49	385.32
Vectren IN	556.70	538.45	476.61	420.53	345.82	268.51	247.98	292.00	317.27	491.09	442.17	360.40	396.46
Dominion OH	413.38	407.75	412.43	334.28	280.20	264.10	317.67	381.14	444.00	531.64	550.94	477.15	401.22
NiSource IN	505.68	543.82	507.62	443.96	374.41	308.65	277.14	312.75	335.30	457.66	413.09	393.59	406.14
ENBRIDGE	416.21	364.00	463.36	441.54	357.37	381.08	412.28	351.33	374.36	406.16	463.11	514.83	412.13
PSE&G NJ	465.16	487.13	494.00	481.81	414.22	335.61	294.09	340.34	347.26	495.02	450.89	377.05	415.21
NWN OR	565.95	594.68	572.40	513.51	407.26	271.33	248.77	301.12	297.77	484.07	418.42	317.75	416.09
Questar UT	520.24	540.77	550.04	518.94	405.67	304.29	280.98	303.52	317.67	473.14	439.02	367.78	418.51
Puget WA	530.06	579.79	599.60	530.39	401.37	275.92	252.96	329.16	367.08	599.10	537.62	424.88	452.33
Iberdrola NY	608.01	598.08	628.25	536.61	445.68	357.07	310.00	333.86	357.10	540.96	502.44	467.44	473.79
WGL DC,MD,VA	611.75	640.44	665.81	563.86	450.19	337.66	306.81	343.00	366.36	533.48	482.78	404.79	475.58
ConED NY	587.03	599.79	598.37	526.03	425.24	328.45	318.54	353.06	404.40	615.50	629.20	530.21	492.99
DTE MI	546.02	740.78	696.00	643.17	553.28	399.39	355.18	396.21	478.19	618.18	559.42	468.51	537.86
National Grid MA	741.15	645.31	666.96	636.16	522.27	449.45	388.21	425.85	454.90	678.73	620.88	553.12	565.25
National Grid NY	714.04	716.95	746.27	692.64	536.39	414.05	370.21	405.05	441.03	654.59	609.33	516.89	568.12
Integrys IL	674.36	691.14	735.84	659.73	554.94	512.36	443.86	525.54	546.50	725.11	656.78	529.28	604.62
National Fuel NY	812.87	835.54	829.80	749.91	617.50	542.94	492.86	495.34	508.14	631.94	562.96	496.06	631.32
25 Company Average	502.77	521.26	521.39	468.87	383.90	303.87	283.00	321.32	350.04	497.90	458.79	387.79	416.74
Subgroup Average	482.88	484.13	495.48	453.15	366.07	284.42	259.79	291.42	314.89	460.21	426.41	359.53	389.86
Enbridge	416.21	364.00	463.36	441.54	357.37	381.08	412.28	351.33	374.36	406.16	463.11	514.83	412.13

Total Cost (Cdn$) Per Volume (10^3 m^3)													Average
Company	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2000 - 2011
NiSource IN	40.98	55.36	50.23	45.73	37.32	32.06	30.38	31.98	33.37	49.80	41.57	36.29	40.42
Nicor IL	41.46	47.85	45.62	43.69	38.84	29.23	28.76	33.16	35.98	54.79	52.87	41.48	41.14
PSCO CO	47.55	50.93	51.76	47.15	38.32	25.34	25.69	30.41	32.23	53.93	52.23	43.39	41.58
CenterPoint MN	53.83	61.14	56.46	52.30	43.08	36.79	35.95	38.61	40.76	60.79	55.83	50.62	48.85
Columbia OH	64.82	64.46	54.30	47.48	39.92	37.01	39.16	49.62	54.42	84.75	76.10	56.41	55.70
WE WI	65.15	71.75	71.73	62.29	54.02	39.03	42.32	42.76	49.71	70.89	73.03	60.05	58.56
ENBRIDGE	52.70	47.11	64.39	56.63	48.88	54.02	63.99	53.07	57.84	63.63	73.08	79.07	59.53
Ameren IL	70.98	78.98	78.18	66.57	56.66	41.63	48.75	52.76	53.96	78.44	67.43	55.13	62.45
Vectren IN	76.78	84.54	73.10	64.60	56.36	43.91	44.42	49.30	51.20	88.79	74.42	60.29	63.98
Dominion OH	58.28	67.93	65.10	52.38	44.10	41.68	55.02	62.80	71.11	97.01	92.41	76.68	65.37
MGE MO	40.23	119.00	43.44	51.25	64.82	47.19	50.77	58.19	61.05	94.29	87.62	79.28	66.43
Consumers MI	71.36	84.68	87.96	77.16	69.60	58.10	55.87	59.52	63.39	98.27	94.95	77.67	74.88
PSE&G NJ	57.23	76.63	75.35	69.92	80.14	67.92	66.24	69.72	73.17	102.13	95.32	76.61	75.86
NWN OR	86.51	99.01	98.81	93.83	74.63	50.23	46.17	56.19	55.24	100.89	93.34	65.89	76.73
Questar UT	85.85	91.30	96.98	104.87	82.06	65.03	59.09	57.26	56.12	88.26	82.62	69.49	78.24
BG&E MD	81.51	91.05	89.61	76.42	70.37	56.57	64.36	66.74	71.07	101.40	93.36	84.79	78.94
ConED NY	91.85	107.42	90.40	93.10	77.63	58.46	51.82	51.41	58.92	88.52	97.80	79.98	78.94
Iberdrola NY	96.99	106.39	108.77	87.94	76.15	62.55	60.75	60.48	64.61	100.92	98.11	90.67	84.53
Laclede MO	99.89	95.14	113.81	91.97	83.67	69.43	71.25	76.39	82.82	118.88	108.15	91.11	91.88
National Grid NY	99.15	104.81	109.94	109.19	97.00	72.50	67.27	68.39	79.19	117.50	105.80	87.64	93.20
Integrys IL	92.37	108.52	108.36	92.69	84.08	79.35	75.37	84.76	83.49	117.16	112.01	88.74	93.91
WGL DC,MD,VA	108.48	136.75	130.32	114.12	96.57	71.67	73.28	73.62	81.05	116.46	100.53	93.05	99.66
Puget WA	99.23	117.93	124.20	115.76	92.22	64.34	58.83	74.64	81.18	139.15	136.09	96.32	99.99
National Grid MA	125.43	112.17	115.38	111.07	96.81	92.91	77.96	81.23	93.44	145.08	99.40	79.35	102.52
DTE MI	67.97	98.58	147.01	125.18	117.29	97.12	101.04	102.41	120.45	163.29	163.01	128.21	119.30
National Fuel NY	136.83	151.77	147.58	129.53	114.03	102.90	104.97	96.79	102.43	132.22	121.90	104.55	120.46
25 Company Average	78.43	91.36	89.38	81.05	71.43	57.72	57.42	61.16	66.01	98.54	91.04	74.95	76.54
Subgroup Average	75.88	83.91	83.88	79.01	69.54	55.88	53.33	55.45	60.24	90.22	79.43	66.20	71.08
Enbridge	52.70	47.11	64.39	56.63	48.88	54.02	63.99	53.07	57.84	63.63	73.08	79.07	59.53

UNDERTAKING TCU1.13

UNDERTAKING

TR Technical Conference, page 141

EGDI to apply the SEIM mechanism to the 2008 to 2012 period as if it were in place, and to advise of the amount of any SEIM reward that would have been requested for 2013 and 2014.

RESPONSE

The calculation below illustrates the potential SEIM reward that the Company would have been able to request, had the SEIM mechanism been an approved component of the first generation IR plan.

	Actual Normalized ROE %	Board Approved ROE %	
2008	9.94%	8.66%	
2009	10.26%	8.31%	
2010	9.21%	8.37%	
2011	8.18%	7.94%	
2012	7.25%	7.52%	
Average	8.97%	8.16%	
Variance	0.81%		
	* 50%		
	* 50%		
Reward Potential	0.20%	or 0.5% (the lesser of the two)	

ROE Premium ($) = 0.20% * $4,162.0M (2013 Approved Rate Base) * 36% (equity ratio) / 0.735 (reciprocal 26.5% tax rate)
= 4.1 ($million)
* 2 2013 and 2014 reward payments
Total SEIM Reward = 8.2 ($million)

The $8.2 million represents the potential amount that EGD would have been able to make an application for, provided that it could substantiate that the ratepayer benefits (i.e., sustainable efficiencies) were greater than this amount, and that EGD's

Witnesses: R. Fischer
S. Kancharla

performance metrics and service quality metrics had not declined since 2007. It should also be noted that use of the 2009 Board Approved ROE formula would have reduced the SEIM ROE potential (by reducing Board Approved ROEs for the 2010-2012 period) and will similarly reduce the potential going forward.

Witnesses: R. Fischer
S. Kancharla

UNDERTAKING TCU2.1

UNDERTAKING

Technical Conference TR 2, page 11

EGDI to provide a response to IR CME No. 2, to the extent that it can be done. To the extent that it cannot, to again explain why.

RESPONSE

In the attached table the Company has attempted to provide information in relation to that requested in CME Interrogatory #2 found at Exhibit I.A1.EGDI.CME.2. While the request asked for a columnar approach and for the provision of items, amounts, and percentages not subject to adjustment in future years, EGD has provided a one page summary showing percentage calculations of items subject to adjustment and or deferral or variance account treatment as a result of a better view and ability to identify such items.

Within the total allowed revenue calculated for each year shown at Line 21, the items and amounts subject to adjustment each year is shown at Line 22, with the percentage amount subject to adjustment shown at Line 23. This is a simple view of amounts subject to adjustment however, as items subject to pass through such as gas cost related amounts and amounts subject to separate proceedings and or agreements such as Customer Care/CIS and DSM would change or be adjusted annually in any IR rate setting model.

The Company believes Lines 24 and 25 better represent the total amount and percentage of amounts subject to adjustment annually as they remove gas cost related, Customer Care/CIS and DSM related amounts which should be viewed as pass through items. In addition, regardless of the IR model, the majority of the deferral and variance accounts would continue to be used or required and therefore are a constant to any view of amounts or items subject to such treatment.

Witnesses: K. Culbert
R. Small

Allowed Revenue
And Sufficiency / (Deficiency) As Filed
2014 – 2108 Fiscal Years

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total	
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	
	Cost of Capital						
1.	Rate base	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1	
1a.	GTA Project	-	120.8	571.4	557.1	542.9	GTAPVA
1b.	Relocation Mains	-	-	-	2.2	13.7	RLMVA
1c.	Replacement Mains	-	-	-	0.9	5.5	RPMVA
1d.	Gas in Storage	279.9	291.2	276.3	276.3	276.3	Annual gas supply plan update impacts / PGVA
1e.	Working Cash	43.2	50.0	40.1	40.0	39.9	Annual gas supply plan & O&M update impacts
		323.1	462.0	887.8	876.5	878.3	
2.	Required rate of return	6.74%	6.90%	7.02%	7.04%	7.11%	
3.		298.9	330.8	387.6	403.8	419.9	
3a.	GTA Project	-	8.3	40.1	39.2	38.6	GTAPVA
3b.	Relocation Mains	-	-	-	0.2	1.0	RLMVA
3c.	Replacement Mains	-	-	-	0.1	0.4	RPMVA
3d.	Gas in Storage	18.9	20.1	19.4	19.4	19.6	Annual gas supply plan update impacts / PGVA
3e.	Working Cash						Annual gas supply plan & O&M

Witnesses: K. Culbert
R. Small

Allowed Revenue
And Sufficiency / (Deficiency) As Filed
2014 – 2108 Fiscal Years

Line No.			Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total	
			($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	
			2.9	3.4	2.8	2.8	2.8	update impacts
		a)	21.8	31.8	62.3	61.7	62.4	
	Cost of Service							
4.	Gas costs		1,455.9	1,606.8	1,632.5	1,632.5	1,632.5	
4a.	Gas costs	a)	1,455.9	1,606.8	1,632.5	1,632.5	1,632.5	
5.	Operation and maintenance		425.3	428.5	439.5	450.5	461.8	
5a.	Customer Care/CIS Service Charges		92.6	96.5	100.4	104.4	108.5	
5b.	DSM		32.2	32.8	33.5	34.2	34.9	
5c.	Pension & OPEB		37.2	33.8	30.9	28.5	26.2	
5d.	Ontario Rate Hearing Costs		8.0	6.0	6.0	6.0	6.0	OHCVA
5e.	GTA Project		-	0.3	1.4	1.4	1.5	GTAPVA
		a)	170.0	169.4	172.2	174.5	177.1	
6.	Depreciation and amortization		262.8	276.6	303.9	313.4	322.1	

Witnesses: K. Culbert
R. Small

Allowed Revenue
And Sufficiency / (Deficiency) As Filed
2014 – 2108 Fiscal Years

Line No.			Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total	
			($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	
6a.	GTA Project		-	2.4	14.3	14.3	14.3	GTAPVA
6b.	Relocation Mains		-	-	-	-	0.3	RLMVA
6c.	Replacement Mains		-	-	-	-	0.1	RPMVA
		a)	-	2.4	14.3	14.3	14.7	
7.	Fixed financing costs		1.9	1.9	1.9	1.9	1.9	
8.	Municipal and other taxes		41.2	43.1	45.5	47.9	50.4	
8a.	GTA Project	a)	-	0.4	1.8	1.9	2.0	GTAPVA
9.			2,187.1	2,356.9	2,423.3	2,446.2	2,468.7	
	Miscellaneous operating and non operating revenue							
10.	Other operating revenue		(40.5)	(40.9)	(41.2)	(41.2)	(41.2)	
10a.	Transactional services		(12.0)	(12.0)	(12.0)	(12.0)	(12.0)	TSDA
10b.	Open bill revenue		(5.4)	(5.4)	(5.4)	(5.4)	(5.4)	OBRVA

Witnesses: K. Culbert
R. Small

Allowed Revenue
And Sufficiency / (Deficiency) As Filed
2014 – 2108 Fiscal Years

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
	a)	(17.4)	(17.4)	(17.4)	(17.4)	(17.4)
11.	Other income	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
12.		(40.6)	(41.0)	(41.3)	(41.3)	(41.3)
	Income taxes on earnings					
13.	Excluding tax shield	73.0	56.3	52.9	58.8	67.9
14.	Tax shield provided by interest expense	(39.5)	(42.5)	(48.4)	(50.2)	(52.1)
15.		33.5	13.8	4.5	8.6	15.8
	Taxes on sufficiency / (deficiency)					
16.	Gross sufficiency / (deficiency)	35.1	(20.6)	(106.4)	(147.7)	(192.1)
17.	Net sufficiency / (deficiency)	25.8	(15.2)	(78.2)	(108.6)	(141.2)
18.		(9.3)	5.5	28.2	39.1	50.9
19.	Sub-total Allowed Revenue	2,469.6	2,666.0	2,802.3	2,856.4	2,914.0
20.	Customer Care Rate Smoothing Var. Adj.	(2.9)	(1.1)	0.8	2.9	5.0

Witnesses: K. Culbert
R. Small

Allowed Revenue
And Sufficiency / (Deficiency) As Filed
2014 – 2108 Fiscal Years

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
21.	**Allowed Revenue**	2,466.7	2,664.9	2,803.1	2,859.3	2,919.0
22.	Total a): Allowed Revenue Subject to Adj. or D/A	1,630.3	1,793.4	1,865.7	1,867.5	1,871.3
23.	% of Allowed Rev Subj to Adj. or D/A	66%	67%	67%	65%	64%
24.	Total a) excl. gas costs, gas in storage, CC/CIS, DSM	30.7	37.2	79.9	77.0	75.8
25.	% of Allowed Rev net of pass throughs Subj to Adj or D/A	1%	1%	3%	3%	3%
	Revenue at existing Rates					
26a.	Gas sales	2,253.5	2,404.3	2,464.5	2,480.3	2,496.2
27a.	Transportation service	242.8	229.6	217.1	211.1	205.0
28.	Transmission, compression and storage	1.8	1.8	1.8	1.8	1.8
29.	Rounding adjustment	(0.2)	0.1	-	-	0.3
30.	Total	2,497.9	2,635.8	2,683.4	2,693.2	2,703.3
31.	**Gross revenue sufficiency / (deficiency)**	31.2	(29.1)	(119.7)	(166.1)	(215.7)

Witnesses: K. Culbert
R. Small

UNDERTAKING TCU2.4

UNDERTAKING

Technical Conference TR 2, page 38

EGDI to explain how it undertook the calculations to create the table in response to BOMA Interrogatory No. 2 (Exhibit I.A1.EGDI.BOMA.2).

RESPONSE

Table 2 on page 2 provides calculation detail with respect to the determination of an approximate revenue requirement assuming the Union IRM found in the table in Exhibit I.A1.EGDI.BOMA.2 and reproduced at Table 1 below.

Table 1

Allowed Revenue (Net of Gas Cost)

$ Millions	**2013 Board Approved**	**2014**	**2015**	**2016**	**2017**	**2018**
Customized IR (As applied for)	1,021	1,012	1,058	1,171	1,227	1,286
Incremental over 2013 board approved		(10)	37	149	205	265
Approximation of Union IRM	1,021	974	989	1,050	1,061	1,080
Incremental over 2013 board approved		(47)	(32)	28	40	59

Assumptions for 'Approximation of Union IRM':

- Escalation factor assuming GDPIPI of 1.7%, with 60% productivity factor
- Revenue cap Model
- Y factor treatment for GTA and Ottawa project
- DSM, CIS/Customer Care, Pension cost and carrying cost of Gas In Storage as flow through items
- Adjustment for Reduction in depreciation expense with SRC in 2013 base
- Factor in tax impact of Site Restoration Cost adjustment

Witnesses: R. Fischer
J. Coyne, Concentric Energy Advisors Inc.

Table 2

Backup

Distributed Revenue - IR ($M)	**Rebase 2013**	**Second Generation IR 2014**	**2015**	**2016**	**2017**	**2018**
	ADR					
Escalation factor		1.7%	1.7%	1.7%	1.7%	1.7%
Productivity		-1.0%	-1.0%	-1.0%	-1.0%	-1.0%
Total Escalation factor		0.7%	0.7%	0.7%	0.7%	0.7%
Revenue Requirement - COS	**817**	817				
RR of Red'n in dep'n expense with SRC in 2013 base year		(39)				
Adj Revenue Requirement COS - Subject to escalation		**778**				
Revenue Requirement - IR with escalation		**784**	**789**	**794**	**800**	**805**
Y factor						
Carrying cost for Gas in Storage	20	20	20	21	21	21
Pension cost	43	37	34	31	30	28
DSM	31	32	33	33	34	35
Y factor for Customer Care	110	114	119	124	129	134
Y factor for GTA&Ottawa	-	5	12	62	62	62
Site Restoration Cost - Tax impact	-	(18)	(17)	(15)	(14)	(5)
	204	191	201	256	262	275
Total Distribution Revenues -IR	**1,021**	**974**	**989**	**1,050**	**1,061**	**1,080**
Achieved ROE (based on EGD required budgets)	**8.9%**	**7.5%**	**6.8%**	**5.6%**	**4.2%**	**3.1%**

Workings					
Ratebase	4,442	4,798	5,524	5,737	5,906
Equity thickness	36%	36%	36%	36%	36%
Deemed Equity	1,599	1,727	1,989	2,065	2,126
Utility Earnings	121	117	112	88	66
Achieved ROE (based on EGD required budgets)	7.5%	6.8%	5.6%	4.2%	3.1%

Witnesses: R. Fischer
J. Coyne, Concentric Energy Advisors Inc.

UNDERTAKING TCU2.5

UNDERTAKING

Technical Conference TR 2, page 47

Enbridge to consider and respond as it deems appropriate to questions about producing its current budget and other budgets that exist for Concentric's work, and questions about whether there is any written record of seeking approval from the EGD President or Board for increases in Concentric costs.

RESPONSE

EGD has provided an update of the cost to date (as at the time of Interrogatories) for the Concentric work as filed in response to CCC Interrogatory #1 found at Exhibit I.A1.EGDI.CCC.1.

Beyond the documents already produced, there is no further written record evidencing formal written approval for either a re-budget or re-scoping of Concentric's work on behalf of EGD. The evolution of Concentric's role was an iterative process, responding to the evolution of EGD's 2013 (and then 2014 to 2018) rate applications, and responding to EGD's direction in response to OEB-initiated processes such as the OEB's IR Review for Ontario gas utilities in which PEG was engaged (EB-2011-0052) and the OEB's RRFE Report, which introduced the "Custom IR" method of rate setting.

Among the issues that arose over time that increased the scope and the costs of Concentric's work beyond those which could have reasonably been forecast by EGD or Concentric when the engagement was first initiated are:

- EGD's Decision to split the Rebasing and IR applications, which involved significant roles by Concentric in two separate cases
- The OEB initiated IR Review, which required EGD to be prepared to respond to PEG's findings and observations
- EGD's Decision to move from an 'I-X' IR model to a Customized IR model

EGD was regularly apprised of the cost status by Concentric and this information was regularly shared verbally with members of EGD's Executive Management Team, who

Witnesses: R. Fischer
S. Kancharla

approved the continuation of the work to date. From EGD's perspective, these costs are legitimately within the Hearing Costs budget, and EGD would only seek recovery for amounts over the OHCVA threshold.

Witnesses: R. Fischer
S. Kancharla

UNDERTAKING TCU2.9

UNDERTAKING

Technical Conference TR 2, page 59

To provide a response to SEC Technical Conference Question 13. (Exhibit TC 1.3)

RESPONSE

See following response

SEC Technical Conference Question 13

Ref: I.A1.EGDI.CCC.2 Attachment 1

With respect to the April 30, 2013 report to the Board of Directors:

a. P.2. Please provide a breakdown of the average net overearnings of 131 basis points between "reductions in debt interest rates and tax rates" and "cost efficiency".
b. P. 3. Please provide a table by year showing the extent, in total dollars annually, to which i) the reduction in the annual contribution to the site restoration reserve" and ii) the drawdown of the accumulated reserve amount" will "buffer the customer rate increases".
c. P. 5. Please provide details of the factors that are expected to cause the "return on deemed equity - utility" to be greater than the "allowed ROE" for each of 2014 through 2016. Please provide similar projections for 2017 and 2018.

Enbridge provides the following response:

a) Referencing the table in response to Board Staff Interrogatory #4 found at Exhibit I.A1.EGDI.STAFF.4, which does not take into account the impact of the accounting error identified in EGDI's September 30, 2013, the average net overearnings after earnings sharing over the term of the 1st Generation IR was actually 164 basis points rather than the 131 basis points stated in the Board of Director's memo. On a before earnings sharing basis the average net overearnings was 227 basis points.

b) Please see the table on the following page.

Witness: S. Kancharla

Line No.		Col. 1 2014 EGD Total	Col. 2 2015 EGD Total	Col. 3 2016 EGD Total	Col. 4 2017 EGD Total	Col. 5 2018 EGD Total	Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Allowed Revenues Excl. SRC Proposal (Exh. I.A16.EGDI.EP.11, page 2, Line 21)	2,528.6	2,720.7	2,855.3	2,903.5	2,946.2	13,954.4
2.	Allowed Revenues As Filed (Exh. F1, T1, S2, pages 1 to 5, Line 22, Col. 4)	2,466.7	2,664.9	2,803.1	2,859.3	2,919.0	13,713.0
3.	Reduction In Allowed Revenues Due SRC Proposal	61.9	55.9	52.2	44.2	27.2	241.4
4.	SRC Refund Through Rider D	68.1	63.1	58.1	53.1	17.4	259.8
5.	Total Ratepayer Benefit From SRC Proposal	130.0	119.0	110.3	97.3	44.6	501.2

c) Enbridge expects that any overearning during the term of the Customized IR plan will be due to the implementation of as yet unidentified productivity initiatives.

Witness: S. Kancharla

UNDERTAKING TCU3.21

UNDERTAKING

Technical Conference TR 3, page 93

With reference to Energy Probe Technical Questions 6 and 7 (Exhibit TC2.2), which relate to Exhibit I.B18.EGDI.EP 22(c), EGDI to provide, when the information is available, corrected schedules, impact on rate base and approximate impact on level of deficiency for 2014 resulting from the correction to the lag days that has been identified, and to provide an update to Energy Probe 22 (Exhibit I.B18.EGDI.EP 22) with corrections shown.

RESPONSE

Attached is an updated response to Energy Probe Interrogatory #22 (I.B18.EGDI.EP.22).

Further the table below provides the approximate impact on rate base and on the level of deficiency for the 2014 to 2018 period resulting from the correction to the lag days.

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	
Line No.		2014 EGD Total	2015 EGD Total	2016 EGD Total	2017 EGD Total	2018 EGD Total	Total
		($Millions)	($Millions)	($Millions)	($Millions)	($Millions)	($Millions)
1.	Updated Rate Base (lag day and HST impacts on working cash)	4,397.5	4,758.6	5,482.5	5,694.6	5,864.0	
2.	Rate Base As Filed (Exh. F1, T1, S2)	4,431.6	4,797.6	5,524.4	5,736.6	5,906.1	
3.	Reduction In Rate Base	(34.1)	(39.0)	(41.9)	(42.0)	(42.1)	
4.	Updated Gross Sufficiency / (Deficiency) (lag day and HST impacts on working cash)	33.3	(26.6)	(116.7)	(162.9)	(212.4)	(485.3)
5.	Gross Sufficiency / (Deficiency) As Filed (Exh. F1, T1, S2)	31.2	(29.1)	(119.7)	(166.1)	(215.7)	(499.4)
6.	Change in Gross Sufficiency / (Deficiency)	2.1	2.5	3.0	3.2	3.3	14.1

Witnesses: K. Culbert
A. Kacicnik
M. Kirk
R. Small

ENERGY PROBE INTERROGATORY #22

INTERROGATORY

Ref: Exhibit B3, Tab 1, Schedule 3 & Exhibit B4, Tab 1, Schedule 3 & Exhibit B5, Tab 1, Schedule 3.

a) Please show the derivation of each of the net lag days shown in the tables for each of 2014 and 2015.

b) Please show the derivation of each of the net lag days used in the 2013 application in EB-2011-0354.

c) Please explain the differences between the net lag days noted in parts (a) and (b) above. For example, what has changed that has resulted in the net lag days increasing to 8.8 in 2014 from 3.6 in 2013?

d) Please show the calculation of the Harmonized Sales Tax amount for each of 2014, 2015 and 2016, along with the similar calculation for the amount in the 2013 rebasing filing.

e) Has EGDI completed a new lead lag study for the application? If yes, please provide it. If not, when was the last lead lag study completed and reviewed by the Board?

RESPONSE

a) and b)

Gas Cost Lag Day

	2013	2014	2015
Revenue Lag Day	42.2	41.1	40.9
Gas Cost Lag Day	38.2	38.3	38.2
Net Gas Cost Lag Day	4.0*	2.8	2.7

*Note the 3.6 net lag day in 2013 was from the original filing. The Final Rate Order net lag day is 4.0, as per EB-2011-0354, Final Rate Order, Appendix A, page 3, filed on 2013-02-14.

Witnesses: A. Kacicnik
M. Kirk

O&M Lag Day

	2013	2014	2015
Revenue Lag Day	42.2	41.1	40.9
O&M Lag Day	60.9	52.1	52.0
Net O&M Lag Day	-18.7	-11.0	-11.1

Storage Costs Lag Day

	2013	2014	2015
Revenue Lag Day	42.2	41.1	40.9
Storage Costs	-20.3	-24.8	-19.5
Net O&M Lag Day	62.5	65.9	60.4

Storage & Municipal Taxes Lag Day

	2013	2014	2015
Revenue Lag Day	42.2	41.1	40.9
Storage Costs	17.8	17.8	17.8
Net O&M Lag Day	24.4	23.3	23.1

c) In reviewing the details that make up the Net Gas Cost Lag for this response, the Company noticed an error in the cash flow reports used to generate the collection lag, a portion of the revenue lag. The Company has corrected the error and updated the lag days.

The net lag day is the result of subtracting the gas cost lag day from the revenue lag day. Both the gas cost lag day and revenue lag days have been relatively stable. An error in one component of the revenue lag day – the collection lag – was responsible for the large increase in the revenue lag day previously filed. As noted above, the Company has updated the results.

d) The following tables display the calculations of the Harmonized Sales Tax ("HST") amounts reported in evidence for 2013 to 2016. In each table, Column 1 shows the amount of HST the Company is forecast to collect on Revenue items or spend on expense items. It is important to distinguish between gas purchases made in various jurisdictions, as it impacts what level of tax is paid on those purchases (i.e., – GST is paid on gas purchased in Alberta, while HST is paid on gas purchased in Ontario). Column 2 shows the average lag day for each item, and Column 3 is the product of the previous two columns.

SUMMARY OF GST AMOUNTS
FOR WORKING CASH REQUIREMENT
FOR FISCAL YEAR 2013

		Col. 1	Col. 2	Col. 3	
		Rev/Exp	Lag Days	Working Cash Requirement	
1.1	Revenue	(320.1)	25.7	(22.50)	a/
1.2	Gas Purchases HST	79.4	42.4	9.22	a/
1.3	Gas Purchases GST	20.9	40.3	2.31	a/
1.4	O & M	30.0	41.3	3.40	a/
1.5	Capital	62.9	54.5	9.39	a/
1.	Total			1.82	

a/ Col. 1 divided by 365 days times Col. 2

Witnesses: A. Kacicnik
M. Kirk

SUMMARY OF HST AMOUNTS
FOR WORKING CASH REQUIREMENT
FOR FISCAL YEAR 2014

		Col. 1	Col. 2	Col. 3	
		Rev/Exp	Lag Days	Working Cash Requirement	
1.1	Revenue	(326.5)	28.1	(25.15)	a/
1.2	Gas Purchases HST	85.9	43.6	10.26	a/
1.3	Gas Purchases GST	28.3	44.2	3.43	a/
1.4	O & M	29.5	44.0	3.56	a/
1.5	Capital	88.7	57.8	14.06	a/
1.	Total			6.16	

a/ Col. 1 divided by 365 days times Col. 2

SUMMARY OF HST AMOUNTS
FOR WORKING CASH REQUIREMENT
FOR FISCAL YEAR 2015

		Col. 1	Col. 2	Col. 3	
		Rev/Exp	Lag Days	Working Cash Requirement	
1.1	Revenue	(352.7)	29.6	(28.57)	a/
1.2	Gas Purchases HST	84.0	45.9	10.55	a/
1.3	Gas Purchases GST	34.2	44.4	4.17	a/
1.4	O & M	30.0	45.4	3.73	a/
1.5	Capital	108.1	59.5	17.64	a/
1.	Total			7.52	

a/ Col. 1 divided by 365 days times Col. 2

Witnesses: A. Kacicnik
M. Kirk

SUMMARY OF HST AMOUNTS
FOR WORKING CASH REQUIREMENT
FOR FISCAL YEAR 2016

		Col. 1	Col. 2	Col. 3	
		Rev/Exp	Lag Days	Working Cash Requirement	
1.1	Revenue	(370.7)	25.2	(25.62)	a/
1.2	Gas Purchases HST	72.4	38.7	7.67	a/
1.3	Gas Purchases GST	25.5	38.5	2.69	
1.4	O & M	31.5	38.8	3.34	a/
1.5	Capital	58.5	51.5	8.26	a/
1.	Total			(3.66)	

a/ Col. 1 divided by 365 days times Col. 2

e) The Company has updated lead/lag day information for this application, and does so for each QRAM and annual rate case. However, the Company does not file the study in each case. In EBRO 495, the Board identified the Working Cash Study as a non-essential exhibit not needing to be filed with the Company's Test Year Evidence. The derivation of lead/lag days follows the methodology approved by the Board in RP-1999-0001, at Exhibit B2, Tab 1, Schedule 1.

Witnesses: A. Kacicnik
M. Kirk

UNDERTAKING TCU2.15

UNDERTAKING

Technical Conference TR 2, page 109

EGDI to respond to Energy Probe’s Technical Conference Question 2 (Exhibit TC 2.2).

RESPONSE

Energy Probe Technical Conference Question #2

Ref: I.A1.EGDI.SEC.7

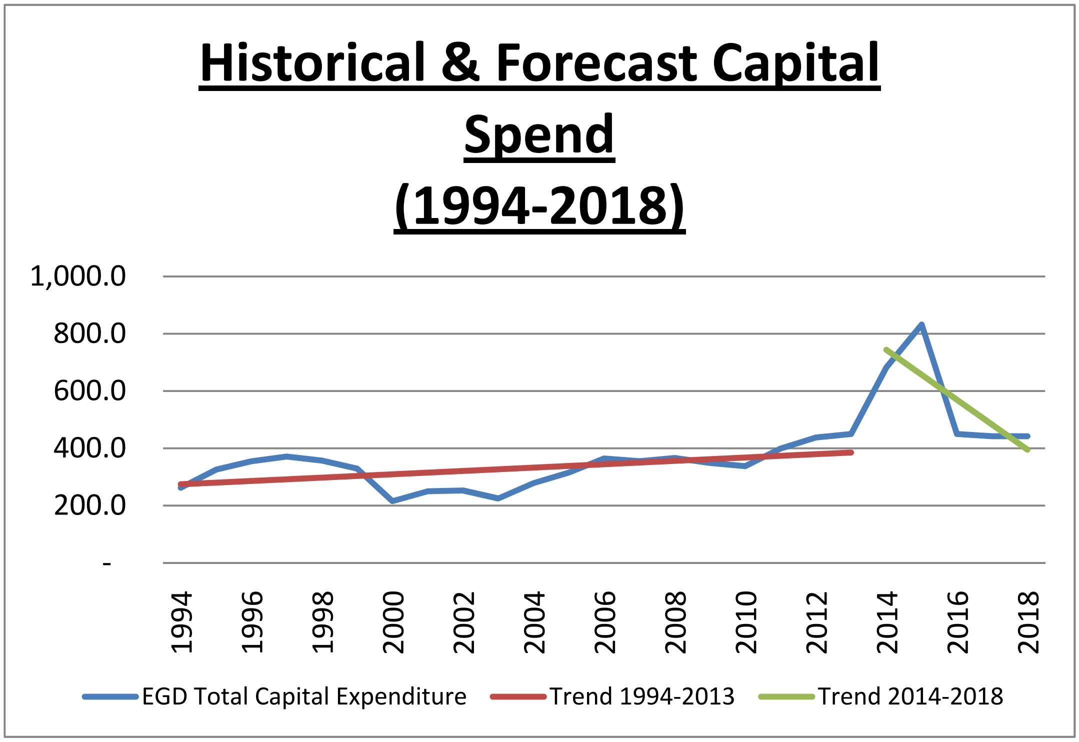
a) Please provide the graphs on pages 1 and 2 of the response that extends the graphs to include the forecast through 2018.

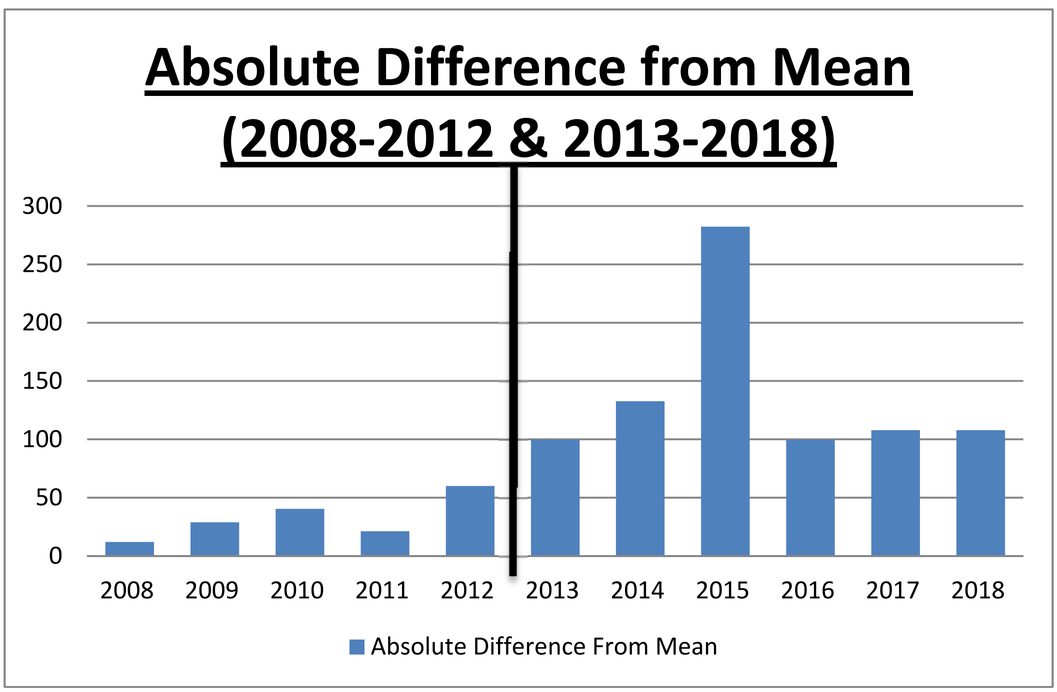
b) Please provide the graphs on pages 1 and 2 of the response that extends the graphs to include the forecast through 2018 but excludes the capital expenditures related to the Ottawa and GTA reinforcement projects.

Enbridge provides the following response:

a) The graphs on the following pages present the referenced graphs including the data extended out to 2018. Note that there was a slight error in the original graphs, which inadvertently double counted the data for some years. This has been corrected in the graphs provided.

Witnesses: R. Fischer
S. Kancharla





/c

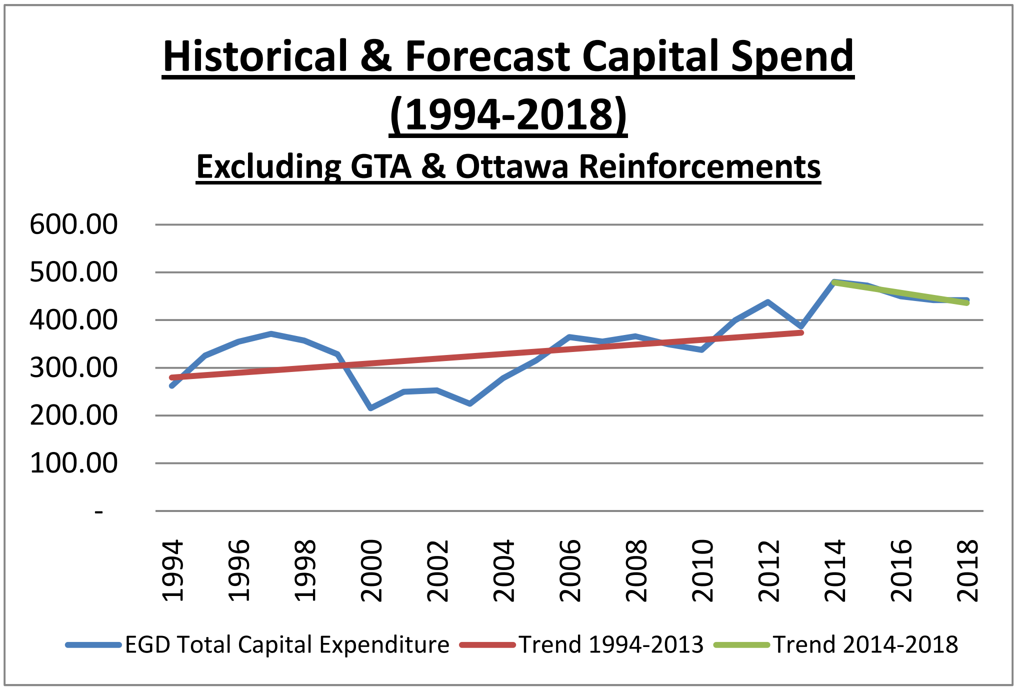
Witnesses: R. Fischer
S. Kancharla

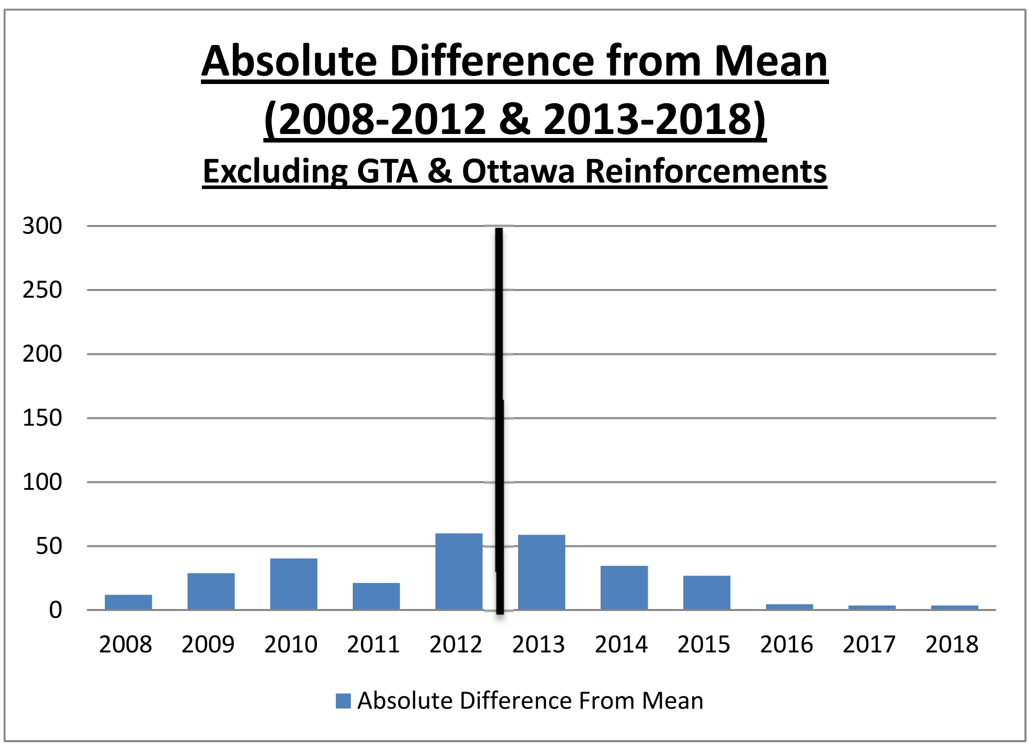
In addition, in the Undertaking TCU2.11, EGD agreed to provide the data underlying the graphs presented here. The table below shows the data for each of the total Capital, Trend line Capital (for the periods 1994 to 2013 and 2014 to 2018, respectively) and the Absolute Difference from the Mean (for the periods 1994 to 2013 and 2014 to 2018, respectively).

	Total Capital	Trendline Capital (1994-2013)	Trendline Capital (2014-2018)	Absolute Difference from Mean (2008-2012)	Absolute Difference from Mean (2013-2018)
1994	$ 262.20	$ 274.31			
1995	$ 325.40	$ 280.14			
1996	$ 354.30	$ 285.97			
1997	$ 371.20	$ 291.80			
1998	$ 357.00	$ 297.64			
1999	$ 328.60	$ 303.47			
2000	$ 215.20	$ 309.30			
2001	$ 249.80	$ 315.14			
2002	$ 252.90	$ 320.97			
2003	$ 224.80	$ 326.80			
2004	$ 278.40	$ 332.64			
2005	$ 315.50	$ 338.47			
2006	$ 364.50	$ 344.30			
2007	$ 354.90	$ 350.14			
2008	$ 366.00	$ 355.97		$ 11.96	
2009	$ 349.10	$ 361.80		$ 28.86	
2010	$ 337.60	$ 367.64		$ 40.36	
2011	$ 399.20	$ 373.47		$ 21.24	
2012	$ 437.90	$ 379.30		$ 59.94	
2013	$ 449.90	$ 385.13			$ 99.77
2014	$ 682.30		$ 743.80		$ 132.63
2015	$ 832.00		$ 656.71		$ 282.33
2016	$ 450.00		$ 569.62		$ 99.67
2017	$ 441.90		$ 482.53		$ 107.77
2018	$ 441.90		$ 395.44		$ 107.77

b) The graphs below present the referenced graphs including the data extended out to 2018, and excluding data for the GTA & Ottawa Reinforcement projects.

Witnesses: R. Fischer
S. Kancharla





/c

Witnesses: R. Fischer
S. Kancharla