VECC INTERROGATORY #7

INTERROGATORY

ISSUE C21: Is the 2014 forecast of Customer Additions appropriate?

Evidence Ref: Cl/T2/S1/ page 2, Table 2 "Summary of Total Average Number of Customers"

a) Based on all available actual 2013 experience to date, please add a column to the referenced table showing EGD's best estimates of total average number of customers which will be realized in 2013.

RESPONSE

The following table provides an additional column of 2013 Forecast based on 2013 9-month actual plus 3-month forecast.

Summary of Total Average Number of Customers

	2013 Board Approved Budget	2013 Forecast 9+3	2014 Budget	2015 Forecast	2016 Forecast
General Service Customers	2 025 038	2 027 483	2 059 216	2 094 900	2 131 485
Contract Market Customers	424	417	403	402	402
Total Number of Customers (Average)	2 025 462	2 027 900	2 059 619	2 095 302	2 131 887

Witnesses: R. Cheung
S. Qian

VECC INTERROGATORY #8

INTERROGATORY

ISSUE C21: Is the 2014 forecast of Customer Additions appropriate?

Evidence Ref: C1/T2/S1/ Appendix B, page 6, Table 3 "General Service and Contract Market Customers"

a) Please confirm that in the referenced table, the actual number of customers was less than the approved number of customers for only 6 of the 18 years shown.

RESPONSE

Confirmed.

Witnesses: R. Cheung
S. Qian

APPrO INTERROGATORY #1

INTERROGATORY

Reference: Exhibit C1 Tab 2, C3 Tab 2 Schedule 3, C4 Tab 2 Schedule 3.

Preamble: APPrO would better like to understand the changing contract market.

Issue: 23. Is the 2014 gas volume forecast appropriate?

Questions:

a) For each year from 2008 to 2013, please provide by rate class:
   i. The forecasted contract customer count used to set rates
   ii. The actual customer count
   iii. The forecasted contract volume used to set rates
   iv. The actual contract volume

b) For each year from 2008 to 2013 please provide a matrix illustrating the number and the respective volumes that have migrated among customer classes.

c) For each year from 2014 to 2016 please provide a matrix illustrating the number and the respective volumes that are forecasted to migrate among customer classes.

d) For those customers that have migrated to a different rate class, please confirm that the respective volumes have been specifically included in the targeted rate class.

e) Enbridge indicates that it forecasts contract volumes individually on grass roots approach in consultation with the customers.
   i. Please explain the decline of 10 Rate 110 customers (combined sales and T-Service) in 2014 compared to 2013
   ii. Please explain the decline of 3 Rate 115 customers (combined sales and T-Service) in 2014 compared to 2013
   iii. Please explain the decline of 6 Rate 145 customers (combined sales and T-Service) in 2014 compared to 2013, and a further 1 customer in 2015
   iv. Please explain the decline of 4 Rate 170 customers (combinedsales and T-Service) in 2014 compared to 2013
   v. Please explain the approximate 26% volumetric increase in Rate 110 volumes between 2013 and 2014 in light of a 5% decline in contract numbers.

Witnesses: R. Cheung
S. Qian

vi. Does Enbridge provide its assessment of its volume forecast toeach customer for each year 2014-2016. Please explain if customers are given the opportunity to agree with the forecast. In the event that there is a difference between Enbridge's forecast and the customers' expectation, what is included in the volumetric forecast?

RESPONSE

a)

i. The following Table 1 shows the forecasted contract customer count by rate class from 2008 to 2013.

TABLE 1
CONTRACT CUSTOMER METERS BY RATE CLASS
2008 - 2013 BUDGET

Item No.	Col. 1 2008 Customers (Average)	Col. 2 2009 Customers (Average)	Col. 3 2010 Customers (Average)	Col. 4 2011 Customers (Average)	Col. 5 2012 Customers (Average)	Col. 6 2013 Customers (Average)
Contract Sales						
Rate 100	543	0	0	0	0	0
Rate 110	259	249	239	204	201	201
Rate 115	62	48	42	34	30	29
Rate 125	2	3	4	4	5	5
Rate 135	36	38	39	33	38	38
Rate 145	154	167	179	187	108	108
Rate 170	34	31	31	39	38	38
Rate 200	1	1	1	1	1	1
Rate 300	9	10	10	9	8	8
Rate 315	0	0	0	0	0	0
Total Contract Sales	1 100	547	545	511	429	428

Witnesses: R. Cheung
S. Qian

ii. The following Table 2 shows the actual contract customer count by rate class from 2008 to 2013.

TABLE 2
CONTRACT CUSTOMER METERS BY RATE CLASS
2008 - 2013 ACTUAL

Item No.	Col. 1 2008 Customers (Average)	Col. 2 2009 Customers (Average)	Col. 3 2010 Customers (Average)	Col. 4 2011 Customers (Average)	Col. 5 2012 Customers (Average)	Col. 6 2013 Customers (Average) YTD Sep
Contract Sales						
Rate 100	709	113	35	15	7	4
Rate 110	243	240	213	205	200	193
Rate 115	49	38	32	28	27	28
Rate 125	3	3	4	4	4	5
Rate 135	40	33	36	42	39	41
Rate 145	175	185	188	126	110	104
Rate 170	34	33	41	37	36	35
Rate 200	1	1	1	1	1	1
Rate 300	10	10	9	8	5	2
Rate 315	0	0	0	0	0	0
Total Contract Sales	1 264	656	559	466	429	413

Witnesses: R. Cheung
S. Qian

iii. The following Table 3 shows the forecasted contract volume by rate class from 2008 to 2013.

TABLE 3
CONTRACT VOLUME BY RATE CLASS
2008 - 2013 BUDGET

Item No.	Col. 1 2008 Volumes (10^6m^3)	Col. 2 2009 Volumes (10^6m^3)	Col. 3 2010 Volumes (10^6m^3)	Col. 4 2011 Volumes (10^6m^3)	Col. 5 2012 Volumes (10^6m^3)	Col. 6 2013 Volumes (10^6m^3)
Contract Sales						
Rate 100	657.6	0.0	0.0	0.0	0.0	0.0
Rate 110	612.9	691.0	562.7	471.9	488.1	487.6
Rate 115	901.1	536.5	425.6	513.1	532.5	421.5
Rate 125	0.0	0.0	0.0	0.0	0.0	0.0
Rate 135	54.2	58.1	58.1	50.0	55.2	55.2
Rate 145	218.2	226.1	222.0	237.3	154.4	152.8
Rate 170	729.3	601.9	543.1	563.2	520.0	516.4
Rate 200	150.0	151.3	156.1	157.4	162.2	163.1
Rate 300	31.9	51.7	41.0	30.0	31.0	31.0
Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
Total Contract Sales	3 355.2	2 316.6	2 008.6	2 022.9	1 943.4	1 827.6

* There is no distribution volume for Rate 125 customers.

iv. The following Table 4 shows the actual contract volume by rate class from 2008 to 2013.

TABLE 4
CONTRACT VOLUME BY RATE CLASS
2008 - 2013 ACTUAL

Item No.	Col. 1 2008 Volumes (10^6m^3)	Col. 2 2009 Volumes (10^6m^3)	Col. 3 2010 Volumes (10^6m^3)	Col. 4 2011 Volumes (10^6m^3)	Col. 5 2012 Volumes (10^6m^3)	Col. 6 2013 Volumes (10^6m^3) YTD Sep
Contract Sales						
Rate 100	592.8	100.3	22.6	10.3	3.7	2.5
Rate 110	664.5	577.6	562.4	546.1	645.1	390.4
Rate 115	635.8	464.5	478.0	558.6	505.6	444.6
Rate 125	0.0	0.0	0.0	0.0	0.0	0.0
Rate 135	57.4	51.9	73.0	61.4	56.5	35.2
Rate 145	243.0	248.3	233.2	184.3	163.4	124.2
Rate 170	689.2	544.4	617.2	522.6	487.9	365.1
Rate 200	183.3	179.3	169.6	168.7	164.6	124.6
Rate 300	35.5	39.3	27.6	30.5	29.6	25.5
Rate 315	0.0	0.0	0.0	0.0	0.0	0.0
Total Contract Sales	3 101.5	2 205.6	2 183.6	2 082.5	2 056.4	1 512.1

* There is no distribution volume for Rate 125 customers.

Witnesses: R. Cheung
S. Qian

b) The following 12 tables from Table 5 to Table 16 provide the matrix illustrating the annual average number of customers and the respective volumes that have migrated among customer class from each year from 2008 to 2013. More specifically:

Table 5 below provides the matrix illustrating the volumes that have migrated among rate classes in 2008 compared to 2007. Table 6 on page 7 provides the matrix illustrating the number of customers that have migrated among rate classes in 2008 compared to 2007.

Table 5
Summary of Customer Migration: 2008 vs 2007
(Volumes in 10^6m^3)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	6.9	0.9	1.2	0.0	0.0	3.4	0.0	**12.4**
	100	378.7	x	9.2	0.0	0.0	0.0	0.6	0.0	**388.5**
	110	33.1	3.0	x	0.0	0.0	0.0	1.2	0.0	**37.3**
	115	2.2	0.0	176.6	x	95.9	0.0	1.5	0.0	**276.2**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	1.5	0.0	0.0	0.0	0.0	x	0.0	0.0	**1.5**
	145	7.5	0.0	0.0	0.0	0.0	0.0	x	0.0	**7.5**
	170	10.7	0.0	0.0	0.0	0.0	0.0	0.0	x	**10.7**
	TOTAL	**433.7**	**9.9**	**186.7**	**1.2**	**95.9**	**0.0**	**6.7**	**0.0**	

Witnesses: R. Cheung
S. Qian

Table 6
Summary of Customer Migration: 2008 vs 2007
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	7	1	1	0	0	4	0	**13**
	100	697	x	16	0	0	0	2	0	**715**
	110	12	3	x	0	0	0	2	0	**17**
	115	2	0	6	x	1	0	1	0	**10**
	125	0	0	0	0	x	0	0	0	**0**
	135	1	0	0	0	0	x	0	0	**1**
	145	7	0	0	0	0	0	x	0	**7**
	170	1	0	0	0	0	0	0	x	**1**
	TOTAL	**720**	**10**	**23**	**1**	**1**	**0**	**9**	**0**	

During 2008, there are 720 contract rate class customers with total volumes of 433.7 10^6m^3 who have migrated to Rate 6. On the other hand, there are 13 contract rate class customers with total volumes of 12.4 10^6m^3 who have migrated from Rate 6.

Witnesses: R. Cheung
S. Qian

Table 7 below provides the matrix illustrating the volumes that have migrated among rate classes in 2009 compared to 2008. Table 8 on page 9 provides the matrix illustrating the number of customers that have migrated among rate classes in 2009 compared to 2008.

Table 7
Summary of Customer Migration: 2009 vs 2008
(Volumes in $10^6 m^3$)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.4	0.3	0.0	0.0	0.0 *	4.6	0.0	**5.3**
	100	371.7	x	10.7	0.0	0.0	0.0	0.0	4.8	**387.2**
	110	25.1	0.5	x	77.7	0.0	0.0	0.0	0.0	**103.3**
	115	0.1	0.0	94.8	x	0.0	0.0	0.0	0.0	**94.9**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.0 *	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.0**
	145	0.8	0.0	2.0	0.0	0.0	0.0	x	6.0	**8.8**
	170	0.0 *	0.0	0.0	0.0	0.0	0.0	2.6	x	**2.6**
	TOTAL	**397.7**	**0.9**	**107.8**	**77.7**	**0.0**	**0.0**	**7.2**	**10.8**	

*Less than 50,000 m^3

Table 8
Summary of Customer Migration: 2009 vs 2008
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	1	1	0	0	1	9	0	**12**
	100	586	x	9	0	0	0	0	1	**596**
	110	14	1	x	1	0	0	0	0	**16**
	115	1	0	7	x	0	0	0	0	**8**
	125	0	0	0	0	x	0	0	0	**0**
	135	1	0	0	0	0	x	0	0	**1**
	145	7	0	1	0	0	0	x	1	**9**
	170	1	0	0	0	0	0	1	x	**2**
	TOTAL	**610**	**2**	**18**	**1**	**0**	**1**	**10**	**2**	

During 2009, there are 610 contract rate class customers with total volumes of 397.7 10^6m^3 who have migrated to Rate 6. On the other hand, there are 12 contract rate class customers with total volumes of 5.3 10^6m^3 who have migrated from Rate 6.

Witnesses: R. Cheung
S. Qian

Table 9 below provides the matrix illustrating the volumes that have migrated among rate classes in 2010 compared to 2009. Table 10 on page 11 provides the matrix illustrating the number of customers that have migrated among rate classes in 2010 compared to 2009.

Table 9
Summary of Customer Migration: 2010 vs 2009
(Volumes in 10^6m^3)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	1.5	0	0	0.7	4.7	0	**6.9**
	100	67.5	x	0.3	0	0	0	0	0	**67.8**
	110	31.4	3.9	x	8.5	0	0	0	0	**43.8**
	115	0	0	12	x	0	0	0	0	**12**
	125	0	0	0	0	x	0	0	0	**0**
	135	0.1	0	0	0	0	x	0	0	**0.1**
	145	3.3	0	2.6	0	0	0	x	0	**5.9**
	170	27.8	0	6.7	0	0	0	0	x	**34.5**
	TOTAL	**130.1**	**3.9**	**23.1**	**8.5**	**0**	**0.7**	**4.7**	**0**	

Table 10
Summary of Customer Migration: 2010 vs 2009
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	2	0	0	1	1	0	**4**
	100	77	x	1	0	0	0	0	0	**78**
	110	22	1	x	2	0	0	0	0	**25**
	115	0	0	3	x	0	0	0	0	**3**
	125	0	0	0	0	x	0	0	0	**0**
	135	1	0	0	0	0	x	0	0	**1**
	145	3	0	1	0	0	0	x	0	**4**
	170	1	0	1	0	0	0	0	x	**2**
	TOTAL	**104**	**1**	**8**	**2**	**0**	**1**	**1**	**0**	

During 2010, there are 104 contract rate class customers with total volumes of 130.1 10^6m^3 who have migrated to Rate 6. On the other hand, there are four contract rate class customers with total volumes of 6.9 10^6m^3 have migrated from Rate 6.

Table 11 below provides the matrix illustrating the volumes that have migrated among rate classes in 2011 compared to 2010. Table 12 on page 13 provides the matrix illustrating the number of customers that have migrated among rate classes in 2011 compared to 2010.

Table 11
Summary of Customer Migration: 2011 vs 2010
(Volumes in $10^6 m^3$)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.0	6.2	0.0	0.0	0.0	0.0	0.0	**6.2**
	100	9.8	x	0.0	0.0	0.0	0.0	0.0	0.0	**9.8**
	110	21.2	7.2	x	28.7	0.0	0.0	0.0	0.0	**57.1**
	115	3.5	0.0	104.4	x	0.0	0.0	0.0	2.0	**109.9**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.5	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.5**
	145	29.2	0.0	2.1	0.0	0.0	0.0	x	0.0	**31.3**
	170	4.0	0.0	19.7	0.0	0.0	0.0	4.4	x	**28.1**
	TOTAL	**68.2**	**7.2**	**132.4**	**28.7**	**0.0**	**0.0**	**4.4**	**2.0**	

Witnesses: R. Cheung
S. Qian

Table 12
Summary of Customer Migration: 2011 vs 2010
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	11	0	0	0	0	0	**11**
	100	21	x	0	0	0	0	0	0	**21**
	110	28	2	x	3	0	0	0	0	**33**
	115	1	0	5	x	0	0	0	1	**7**
	125	0	0	0	0	x	0	0	0	**0**
	135	3	0	0	0	0	x	0	0	**3**
	145	61	0	1	0	0	0	x	0	**62**
	170	2	0	1	0	0	0	1	x	**4**
	TOTAL	**116**	**2**	**18**	**3**	**0**	**0**	**1**	**1**	

During 2011, there are 116 contract rate class customers with total volumes of 68.2 10^6m^3 who have migrated to Rate 6. On the other hand, there are 11 contract rate class customers with total volumes of 6.2 10^6m^3 who have migrated from Rate 6.

Witnesses: R. Cheung
S. Qian

Table 13 below provides the matrix illustrating the volumes that have migrated among rate classes in 2012 compared to 2011. Table 14 on page 15 provides the matrix illustrating the number of customers that have migrated among rate classes in 2012 compared to 2011.

Table 13
Summary of Customer Migration: 2012 vs 2011
(Volumes in $10^6 m^3$)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.0	38.1	0.0	0.0	0.2	0.0	0.0	**38.3**
	100	7.0	x	3.9	0.0	0.0	0.0	0.0	0.0	**10.9**
	110	19.7	2.5	x	0.0	0.0	0.0	0.0	22.2	**44.4**
	115	0.0	0.0	0.0	x	0.0	0.0	0.0	0.0	**0.0**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.9	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.9**
	145	16.3	0.0	0.0	2.3	0.0	0.0	x	0.0	**18.6**
	170	6.7	0.0	0.0	0.0	0.0	0.0	0.0	x	**6.7**
	TOTAL	**50.6**	**2.5**	**42.0**	**2.3**	**0.0**	**0.2**	**0.0**	**22.2**	

Witnesses: R. Cheung
S. Qian

Table 14
Summary of Customer Migration: 2012 vs 2011
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	8	0	0	1	0	0	**9**
	100	8	x	1	0	0	0	0	0	**9**
	110	15	1	x	0	0	0	0	1	**17**
	115	0	0	0	x	0	0	0	0	**0**
	125	0	0	0	0	x	0	0	0	**0**
	135	1	0	0	0	0	x	0	0	**1**
	145	18	0	0	1	0	0	x	0	**19**
	170	1	0	0	0	0	0	0	x	**1**
	TOTAL	**43**	**1**	**9**	**1**	**0**	**1**	**0**	**1**	

During 2012, there are 43 contract rate class customers with total volumes of 50.6 $10^6 m^3$ who have migrated to Rate 6. On the other hand, there are nine contract rate class customers with total volumes of 38.3 $10^6 m^3$ who have migrated from Rate 6.

Witnesses: R. Cheung
S. Qian

Table 15 below provides the matrix illustrating the volumes that have migrated among rate classes in 2013 compared to 2012. Table 16 on page 17 provides the matrix illustrating the number of customers that have migrated among rate classes in 2013 compared to 2012. In this comparison, 2013 data contains 9-month actual along with 3-month forecast for 2013.

Table 15
Summary of Customer Migration: 2013 Forecast 9+3 vs 2012
(Volumes in $10^6 m^3$)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.0	18.5	0.0	0.0	0.4	5.3	0.0	**24.2**
	100	3.8	x	0.0	0.0	0.0	0.0	0.0	0.0	**3.8**
	110	14.2	1.4	x	122.2	0.0	0.0	0.0	0.0	**137.8**
	115	40.2	0.0	6.9	x	0.0	0.0	0.0	0.0	**47.1**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.2	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.2**
	145	8.2	0.0	0.0	0.0	0.0	0.0	x	0.0	**8.2**
	170	0.0	0.0	0.0	0.0	0.0	0.0	0.0	x	**0.0**
	TOTAL	**66.6**	**1.4**	**25.4**	**122.2**	**0.0**	**0.4**	**5.3**	**0.0**	

Table 16
Summary of Customer Migration: 2013 Forecast 9+3 vs 2012
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	5	0	0	1	2	0	**8**
	100	5	x	0	0	0	0	0	0	**5**
	110	10	2	x	2	0	0	0	0	**14**
	115	1	0	1	x	0	0	0	0	**2**
	125	0	0	0	0	x	0	0	0	**0**
	135	1	0	0	0	0	x	0	0	**1**
	145	5	0	0	0	0	0	x	0	**5**
	170	0	0	0	0	0	0	0	x	**0**
	TOTAL	**22**	**2**	**6**	**2**	**0**	**1**	**2**	**0**	

During 2013, there are 22 contract rate class customers with total volumes of 66.6 10^6m^3 who have migrated to Rate 6. On the other hand, there are eight contract rate class customers with total volumes of 24.2 10^6m^3 who have migrated from Rate 6 to contract rate class.

c) The following 4 tables from Table 17 to Table 20 provide the matrix illustrating the annual average number of customers and the respective volumes that have migrated among customer class from each year from 2014 to 2016. More specifically:

Table 17 below provides the matrix illustrating the volumes that are forecast to migrate among rate classes in 2014 compared to 2013. Table 18 on page 19 provides the matrix illustrating the number of customers that are forecast to migrate among rate classes in 2014 compared to 2013. In this comparison, 2013 data contains 9-month actual along with 3-month forecast for 2013.

Table 17
Summary of Customer Migration: 2014 Budget vs 2013 Forecast 9+3
(Volumes in 10^6m^3)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	100	0.0	x	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	110	0.0	0.0	x	6.8	0.0	0.0	0.0	0.0	**6.8**
	115	0.0	0.0	116.8	x	0.0	0.0	0.0	0.0	**116.8**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.0	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.0**
	145	2.5	0.0	0.0	0.0	0.0	0.0	x	0.0	**2.5**
	170	5.8	0.0	0.0	0.0	0.0	0.0	0.0	x	**5.8**
	TOTAL	**8.3**	**0.0**	**116.8**	**6.8**	**0.0**	**0.0**	**0.0**	**0.0**	

Witnesses: R. Cheung
S. Qian

Table 18
Summary of Customer Migration: 2014 Budget vs 2013 Forecast 9+3
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	0	0	0	0	0	0	**0**
	100	0	x	0	0	0	0	0	0	**0**
	110	0	0	x	1	0	0	0	0	**1**
	115	0	0	2	x	0	0	0	0	**2**
	125	0	0	0	0	x	0	0	0	**0**
	135	0	0	0	0	0	x	0	0	**0**
	145	1	0	0	0	0	0	x	0	**1**
	170	1	0	0	0	0	0	0	x	**1**
	TOTAL	**2**	**0**	**2**	**1**	**0**	**0**	**0**	**0**	

During 2014, there are two contract rate class customers with total volumes of 8.3 $10^6 m^3$ forecast to migrate to Rate 6.

Witnesses: R. Cheung
S. Qian

Table 19 below provides the matrix illustrating the volumes that are forecast to migrate among rate classes in 2015 compared to 2014. Table 20 on page 21 provides the matrix illustrating the number of customers that are forecast to migrate among rate class in 2015 compared to 2014.

Table 19
Summary of Customer Migration: 2015 Budget vs 2014 Budget
(Volumes in 10^6m^3)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	100	0.0	x	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	110	0.0	0.0	x	0.0	0.0	0.0	0.0	0.0	**0.0**
	115	0.0	0.0	0.0	x	0.0	0.0	0.0	0.0	**0.0**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.0	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.0**
	145	0.4	0.0	0.0	0.0	0.0	0.0	x	0.0	**0.4**
	170	0.0	0.0	0.0	0.0	0.0	0.0	0.0	x	**0.0**
	TOTAL	**0.4**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	

Table 20
Summary of Customer Migration: 2015 Budget vs 2014 Budget
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	0	0	0	0	0	0	**0**
	100	0	x	0	0	0	0	0	0	**0**
	110	0	0	x	0	0	0	0	0	**0**
	115	0	0	0	x	0	0	0	0	**0**
	125	0	0	0	0	x	0	0	0	**0**
	135	0	0	0	0	0	x	0	0	**0**
	145	1	0	0	0	0	0	x	0	**1**
	170	0	0	0	0	0	0	0	x	**0**
	TOTAL	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	

During 2015, there is one Rate 145 customer with total volumes of 0.4 $10^6 m^3$ forecast to migrate to Rate 6.

The Company does not expect any customer migrations between the years 2015 to 2016.

d) Confirmed. The respective volumes and the number of customers that have migrated to different rate class over the years have been accounted to the targeted rate classes, which are listed in the tables from Table 1 to 4 of Response a).

Witnesses: R. Cheung
S. Qian

e) The following Table 21 provides the customer migrations matrix illustrating the volumes that are forecast to migrate among rate classes in 2014 compared to 2013 Board Approved Budget. Table 22 on page 23 provides the customer migrations matrix illustrating the number of customer that are forecast to migrate among rate classes in 2014 compared to the 2013 Board Approved Budget.

Table 21
Summary of Customer Migration: 2014 Budget vs 2013 Board Approved Budget
(Volumes in 10^6m^3)

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0.0	59.2	0.0	0.0	2.9	9.4	0.0	**71.5**
	100	0.0	x	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**
	110	24.1	0.0	x	19.9	0.0	0.0	0.0	0.0	**44.0**
	115	0.0	0.0	111.1	x	0.0	0.0	0.0	4.0	**115.1**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	1.4	0.0	0.0	0.0	0.0	x	0.0	0.0	**1.4**
	145	11.2	0.0	0.0	0.0	0.0	0.0	x	0.0	**11.2**
	170	30.6	0.0	0.0	0.0	0.0	0.0	4.6	x	**35.2**
	TOTAL	**67.3**	**0.0**	**170.3**	**19.9**	**0.0**	**2.9**	**14.0**	**4.0**	

Table 22
Summary of Customer Migration: 2014 Budget vs 2013 Board Approved Budget
Number of Customers

Switch	Rate Class	To								
		6	100	110	115	125	135	145	170	**TOTAL**
From	6	x	0	10	0	0	4	6	0	**20**
	100	0	x	0	0	0	0	0	0	**0**
	110	22	0	x	2	0	0	0	0	**24**
	115	0	0	4	x	0	0	0	1	**5**
	125	0	0	0	0	x	0	0	0	**0**
	135	1	0	0	0	0	x	0	0	**1**
	145	14	0	0	0	0	0	x	0	**14**
	170	3	0	0	0	0	0	2	x	**5**
	TOTAL	**40**	**0**	**14**	**2**	**0**	**4**	**8**	**1**	

i. The decline of 10 Rate 110 customers arises from a total of 24 Rate 110 customers forecast to migrate to other customer classes, offset by a total of 14 customers forecast to migrate from other customer classes to Rate 110.

ii. The decline of three Rate 115 customers arises from a total of five Rate 115 customers forecast to migrate to other customer classes, offset by a total of two customers forecast to migrate from Rate 110 to Rate 115.

iii. The decline of six Rate 145 customers arises from a total of 14 Rate 145 customers forecast to migrate to Rate 6, offset by total of eight customers forecast to migrate from other customer classes to Rate 145.

iv. The decline of four Rate 170 customers arises from a total of five Rate 170 customers forecast to migrate to other customer classes, offset by one customer forecast to migrate from Rate 115 to Rate 170.

v. As shown in Table 21, the volumetric increase of 130.1 10^6m^3 or 26% in Rate 110 is mainly due to total of 170.3 10^6m^3 that is forecast to migrate from other customer classes to Rate 110. It is partially offset by total of 44.0 10^6m^3 that is forecast to migrate from Rate 110 to other customer classes.

vi. 2014 to 2016 contract market volumes forecasts are determined through a grass-root approach on an individual customer basis. During the budget process, Enbridge provides the customers with their three year historic actual consumptions, including their peak day and peak hour load to assist the customers on providing their forecasted volumes. For the 2014 Forecast, customers provided 12-month forecasted volumes. For forecasted volumes beyond 2014, some customers provided different forecasted volumes compared to 2014 if they projected their business requirements are changing. However, most customers provided their 2015 to 2016 forecasted volumes based on 2014 Forecast.

As stated in Exhibit A2, Tab 3, Schedule 1, Enbridge proposes to submit to the Board an annual update of volumes within the 2015 to 2018 Rate Adjustment proceedings. Therefore, contract customers will have the opportunity to update their forecasted volumes through the annual adjustment mechanism.

Witnesses: R. Cheung
S. Qian

APPrO INTERROGATORY #2

INTERROGATORY

Reference: Exhibit C1 Tab 2, and Exhibit C2 Tab 1 Schedule 1

Preamble: Enbridge is predicting a very marginal increase in contract volumes in light of significantly improving economic conditions. Specifically the Ontario Economic Outlook is improving in 2014, 2015 and 2016 over 2013 shows:

- Real GDP increasing from 2.0% to 2.8%
- Unemployment declining from 7.8% to 6.4%
- Employment Growth increasing from 1.1% to 1.5%

These trends generally are a reversal of the trends that existed between 2008-2012.

Issue: 23. Is the 2014 gas volume forecast appropriate?

Questions:

a) Please identify the specific economic indicators that were used to develop the contract customer and volume forecast.

b) What methodology does Enbridge use to forecast new contract customers and their respective volumes for 2015 and 2016?

c) In light of these improving economic indicators, please indicate why there are no new contract customers forecasted in 2015 and 2016.

RESPONSE

a) Forecasts for contract market volumes are determined on an individual customer basis. Forecast volumes are provided by the customers based on the nature of their business and their own perceptions of the economic climate.

b) As stated in response in part vi of question e) in response to APPrO Interrogatory #1 at Exhibit I.C23.EGDI.APPrO.1, 2015 to 2016 forecasted volumes are projections from the 2014 Forecast on an individual customer basis. Enbridge expects to provide annual update of volumes for 2015 to 2016 within Rate Adjustment

Witnesses: R. Cheung
M. Giridhar
H. Sayyan
M. Suarez
S. Qian

proceedings, in which the forecast of new contract customers will be revisited during the respective budget cycles.

c) Contract market forecast volumes are usually based on a 12-month period. It is difficult for Enbridge to forecast new customers beyond the 12-month period as the contracts are constructed on an annual basis. Further, new customers may not qualify under contract market rate classes. Even customers that do qualify may not want to commit themselves to the contract parameters and instead may start new accounts in Rate 6. Although the economic forecast is showing improvement from 2014 to 2016, there are still uncertainties in the current business environment. Forecasting for longer timeframes becomes difficult until markets demonstrate sustained growth.

Witnesses: R. Cheung
M. Giridhar
H. Sayyan
M. Suarez
S. Qian

APPrO INTERROGATORY #3

INTERROGATORY

Reference: Exhibit C1 Tab 2 Table 3

Preamble: Enbridge is illustrating unbundled contract demand volumes.

Issue: 23. Is the 2014 gas volume forecast appropriate?

Questions:

a) Please identify the unbundled CD volumes by rate class.

b) Please confirm that the volumes in the table are annual billing determinants rather than the sum of contract demands among contract customers.

RESPONSE

a) The following table illustrates the unbundled contract demand volumes by rate class.

Summary of Unbundled Customers Contract Demand Volumes
(Volumes in $10^6 m^3$)

	2013 Board Approved Budget	2014 Budget	2015 Forecast	2016 Forecast
Rate 125	119.2	119.2	119.2	119.2
Rate 300	0.3	0.2	0.2	0.2
Total Contract Demand Volumes	119.5	119.4	119.4	119.4

b) The Company confirms that the volumes in the above table are annual billing determinants for unbundled contract customers, and the volumes represent the sum

Witnesses: R. Cheung
S. Qian

of annual contract demands among unbundled contract customers. For individual contract customers, the annual contract demand is calculated as the monthly contract demand multiplied by 12.

Witnesses: R. Cheung
S. Qian

APPrO INTERROGATORY #4

INTERROGATORY

Reference: Exhibit C3 Tab 2, C4 Tab 2, C5 Tab 2 and Exhibit A2 Tab 3 Schedule 1 paragraphs 18 and 21.

Preamble: It is not clear how Enbridge will be adjusting for contract volumes in each of 2015 and 2016.

Issue: 23. Is the 2014 gas volume forecast appropriate?

Questions:

a) In paragraph 18 of the last reference, Enbridge indicates that it will be using customer additions to determine volume forecast. Also in paragraph 21 of the last reference, Enbridge also indicates that it will be using “other volume forecast”. Please explain how Enbridge will adjust for contract volumes in 2015 and 2016.

b) Is it Enbridge’s intention to refresh its forecast contract volume forecast in its 2015 and 2016 rate filings and use these to set 2015 and 2016 rates?

RESPONSE

a) and b)

As part of each annual Rate Adjustment Application within the proposed IR plan period (2015 to 2018), the Company will refresh the contract volume forecast (i.e., the forecast re-fresh will take place each year). The refreshed forecast will then be used to set rates for the forecast year in question.

Witnesses: R. Cheung
K. Culbert
R. Fischer
A. Kacicnik
M. Lister
S. Qian

CME INTERROGATORY #11

INTERROGATORY

Issue: C23

Reference: Exhibit C1, Tab 2, Schedule 1, page 1

The evidence indicates that EGDI's forecasts for each of the years 2014, 2015 and 2016 will be lower than the Board approved volumes for 2013. Please provide the following further information:

(a) The revenue requirement impact of increasing, proportionately. the General Service and Contract Market volumes for 2014, 2015 and 2016 to the level approved by the Board in 2013, namely, \$11,504.4 $10^6m^{3.}$

RESPONSE

a) The impact of increasing the 2014 volumes to the same level of 2013 Board approved is approximately \$15.2 million increase in margin, and correspondingly the 2014 revenue sufficiency would increase by the same amount.

The impact of increasing the 2015 volumes to the same level of 2013 Board approved is approximately \$11.6 million increase in margin, and correspondingly the 2015 revenue deficiency would decrease by the same amount.

The impact of increasing the 2016 volumes to the same level of 2013 Board approved is approximately \$7.6 million increase in margin, and correspondingly the 2016 revenue deficiency would decrease by the same amount

Witnesses: K. Culbert
R. Cheung
S. Qian

VECC INTERROGATORY #6

INTERROGATORY

ISSUE C23: Is the 2014 gas volume forecast appropriate? Exhibit: I.C23.EGD.VECC.6

Evidence Ref: Cl/T2/S1/ page 1, Table 1"Summary of Gas Sales and Transportation Volumes"

a) Please augment the referenced table with a column that provides the most up-to-date available 2013 actuals and forecasted volumes, e.g., if a 10-month actual plus 2- month forecast is available for 2013, please provide it; if not, please provide a 2013 9-month actual plus 3-month forecast for 2013.

b) Please augment the referenced table with two more columns which provides the actual and weather-normalized volumes for 2012 on the same basis as the column provided i n the previous part of this question. For example, if a 10+2 (forecasted months plus actual months) was provided in part a) for 2013, please break down the comparable 2012 figures into a comparable 10 + 2 format, showing the actual volumes for the first 10 months and the actual volumes for the last 2 months.

RESPONSE

a) & b)

Table 1 on page 2 provides additional columns of 2013 Forecast based on 2013 9-month actual plus 3-month forecast, and 2012 weather-normalized actual volumes.

Witnesses: R. Cheung
S. Qian

Table 1

Summary of Gas Sales and Transportation Volumes

(Volumes in $10^6 m^3$)

	(b) 2012 9-Months Actual	(b) 2012 3-Months Actual	(b) 2012 Actual	(a) 2013 9-Months Actual	(a) 2013 3-Months Forecast	(a) 2013 9&3 Forecast	2013 Board Approved Budget	2014 Budget	2015 Forecast	2016 Forecast
General Service Volumes	6 915.5	2 343.6	9 259.1	7 116.3	2 392.2	9 508.5	9 558.9	9 190.0	9 272.2	9 369.1
Contract Market Volumes	1 537.1	535.5	2 072.6	1 512.1	509.6	2 021.7	1 945.5	1 966.0	1 977.3	1 979.3
Total Volumes, Gas Sales and Transportation	8 452.6	2 879.1	11 331.7	8 628.4	2 901.8	11 530.2	11 504.4	11 156.0	11 249.5	11 348.4
Degree Days	2 588	944	3 532	2 632	968	3 600	3 668	3 517	3 517	3 517

Witnesses: R. Cheung
S. Qian

VECC INTERROGATORY #9

INTERROGATORY

ISSUE C23: Is the 2014 gas volume forecast appropriate?

Evidence Ref: C1/T2/S1/ page 5, Table 3 "Summary of Unbundled Customers Contract Demand Volumes"

a) Please provide EGD's best estimate of 2013 actual contract demand volumes if different from the figure shown.

RESPONSE

The following table provides an additional column of 2013 Forecast based on 2013 9-month actual plus 3-month forecast.

Table 3
Summary of Unbundled Customers Contract Demand Volumes
(Volumes in $10^6 m^3$)

	2013 Board Approved Budget	2013 Forecast 9+3	2014 Budget	2015 Forecast	2016 Forecast
Total Contract Demand Volumes	119.5	117.8	119.4	119.4	119.4

Witnesses: R. Cheung
S. Qian

VECC INTERROGATORY #10

INTERROGATORY

ISSUE C23: Is the 2014 gas volume forecast appropriate?

Evidence Ref: C1/T2/S1/ page 1, Table 1, "Summary of Gas Sales and Transportation Volumes" and page 5, Table 3,"Summary of Unbundled Customers Contract Demand Volumes"

a) Please explain the difference between the "Contract Market Volumes" shown in Table 1and the "Total Contract Demand Volumes" shown in Table 3.

RESPONSE

The Contract Market Volumes shown in Table 1 of Exhibit C1, Tab 2, Schedule 1 provides the annual gas distribution volumes forecast of the Contract Market Customers.

Unbundled Customers use the Company's distribution network for the distribution of their natural gas to their location and do not get billed for distribution volumetrically. The Unbundled Contract Customers incur monthly contract demand charges and generate fixed contract demand revenue.

The Total Contract Demand Volumes shown in Table 3 presents the annual contract demand volumes of the Unbundled Customers.

Witnesses: R. Cheung
S. Qian

ENERGY PROBE INTERROGATORY #27

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 2

Paragraph 1 indicates that the purpose of the evidence is to provide the forecast methodologies for the various weather zones for the 2014 test year and over the customized IR term to 2016. Paragraph 21 indicates the methodologies that EGD is proposing to use over the term of the customized IR term.

a) How will degree day forecasts be set for 2017 and 2018?

b) Paragraph 22 appears to indicate that the methodologies approved for 2014 will continue to be those used in subsequent years, with the only change being the addition of actual data each year and the removal of one year (where applicable). Is this correct?

RESPONSE

a) The forecast methodologies proposed are for the entire Customized IR term from 2014 to 2018. The reference to the year 2016 is incorrect, and should be 2018.

b) This is correct. The methodologies proposed are for the period of the Customized IR term. The resulting forecasts will be updated to include each year of additional data (and removal of one year if applicable) according to the methodology that applies.

Witnesses: H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #28

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 2

a) Please provide the 2014 forecast of degree days for each of the top three methodologies from each of Tables 2, 4 and 6.

b) Please add the simple average of the top three methodologies in each of the Central, Eastern and Niagara zones as a separate methodology and provide the same analysis as found in Tables 1 through 6.

c) Please provide a revised Table 7 for the Central zone that includes the simple average of the three best individual methodologies from the Central zone.

RESPONSE

a) 2014 Forecasts for the top three methodologies identified in Tables 2, 4, and 6 are shown below.

Central	2014F
20-yr Trend	3,432
10-yr-MA	3,671
50/50 (20-yr Trend & 30-yr-MA)	3,628

Eastern	2014F
de Bever with Trend	4,278
20-yr Trend	4,133
Energy Probe	4,275

Niagara	2014F
10-yr-MA	3,441
50/50 (20-yr Trend & 30-yr-MA)	3,384
20-yr Trend	3,242

b) The top three methodologies identified for the Central region over the period from 1990 to 2012 are the same top three methodologies that have shown consistent strength over the long term. Please see pre-filed evidence at Exhibit C2, Tab 1, Schedule 2.

Witnesses: H. Sayyan
M. Suarez

The Company did not test the long-term persistence of the current top three rankings for the Eastern and Niagara regions.

Table 1:

CENTRAL

Actual and Predicted Central weather zone Environment Canada Degree Days ('out-of-sample'), 1990 to 2012

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 11*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Calendar Year	Actual	Naïve	10-yr MA	20-yr MA	20-yr Trend	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	Average of 10-yr MA, 20-yr Trend and 50/50
1990	3,631	4,076	4,110	4,188	4,003	4,179	4,091	4,019	3,964	3,981	4,068
1991	3,686	4,250	4,111	4,186	4,029	4,187	4,108	4,088	4,098	4,176	4,083
1992	4,112	3,631	4,036	4,152	3,927	4,174	4,050	3,984	3,878	3,918	4,004
1993	4,180	3,686	3,990	4,128	3,829	4,166	3,997	3,930	3,692	3,689	3,938
1994	4,115	4,112	3,982	4,105	3,883	4,166	4,025	3,996	3,831	3,830	3,963
1995	4,040	4,180	3,994	4,117	3,879	4,168	4,023	4,067	3,962	3,943	3,965
1996	4,177	4,115	3,991	4,111	3,894	4,166	4,030	4,087	4,017	4,019	3,972
1997	4,026	4,040	3,984	4,113	3,865	4,155	4,010	4,109	4,032	4,029	3,953
1998	3,220	4,177	4,003	4,098	3,926	4,152	4,039	4,140	4,067	4,074	3,990
1999	3,539	4,026	4,029	4,090	3,922	4,143	4,032	4,120	4,037	4,031	3,994
2000	3,826	3,220	3,944	4,027	3,787	4,107	3,947	3,928	3,829	3,768	3,893
2001	3,420	3,539	3,873	3,992	3,710	4,082	3,896	3,834	3,768	3,688	3,826
2002	3,630	3,826	3,892	3,964	3,727	4,065	3,896	3,814	3,779	3,762	3,838
2003	3,982	3,420	3,866	3,928	3,634	4,041	3,837	3,693	3,557	3,570	3,779
2004	3,798	3,630	3,817	3,900	3,604	4,009	3,807	3,640	3,548	3,603	3,743
2005	3,797	3,982	3,797	3,896	3,644	4,010	3,827	3,813	3,711	3,775	3,756
2006	3,378	3,798	3,766	3,878	3,656	3,996	3,826	3,848	3,737	3,802	3,749
2007	3,722	3,797	3,741	3,863	3,668	3,989	3,828	3,860	3,739	3,831	3,746
2008	3,837	3,378	3,662	3,832	3,581	3,952	3,766	3,748	3,655	3,650	3,670
2009	3,836	3,722	3,631	3,830	3,548	3,937	3,742	3,745	3,670	3,648	3,641
2010	3,501	3,837	3,693	3,818	3,582	3,915	3,749	3,777	3,703	3,716	3,674
2011	3,648	3,836	3,722	3,798	3,642	3,902	3,772	3,813	3,739	3,768	3,712
2012	3,215	3,501	3,690	3,791	3,557	3,873	3,715	3,745	3,674	3,696	3,654

Table 2:

CENTRAL

Out of sample forecast performance all available years (1990-2012)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.7%	9	11.0%	9	2.3%	3	61%	4	286	10	35	*8*
10-yr MA	6.5%	2	8.9%	3	4.0%	6	61%	4	148	5	20	*3*
20-yr MA	7.3%	7	10.4%	8	6.9%	9	74%	9	137	3	36	*9*
20-yr Trend	6.6%	4	8.0%	1	0.7%	1	39%	4	153	7	17	*2*
30-yr MA	9.0%	10	11.8%	10	8.9%	10	91%	10	104	1	41	*10*
50% 20-yr Trend / 50% 30-yr MA	6.6%	3	9.2%	4	4.8%	8	61%	4	126	2	21	*4*
de Bever	7.2%	5	9.8%	7	4.6%	7	65%	8	152	6	33	*7*
de Bever with Trend	7.3%	6	9.4%	5	2.2%	2	57%	3	164	8	24	*5*
Energy Probe	7.5%	8	9.5%	6	2.5%	4	52%	1	166	9	28	*6*
Average of 10-yr MA, 20-yr Trend and 50/50	6.5%	1	8.5%	2	3.2%	5	52%	1	141	4	13	*1*

Witnesses: H. Sayyan
M. Suarez

Table 3:

EASTERN

Actual and Predicted Eastern weather zone Environment Canada Degree Days (‘out-of-sample’), 1990 to 2012

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 11*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Calendar Year	Actual	Naïve	10-yr MA	20-yr MA	20-yr Trend	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	Average of de Bever with Trend, 20-yr Trend and Energy Probe
1990	4,250	4,640	4,579	4,670	4,483	4,688	4,585	4,620	4,490	4,472	4,482
1991	4,303	4,931	4,613	4,682	4,543	4,695	4,619	4,674	4,639	4,648	4,610
1992	4,861	4,250	4,546	4,649	4,479	4,688	4,583	4,599	4,524	4,525	4,509
1993	4,780	4,303	4,533	4,625	4,424	4,679	4,551	4,538	4,453	4,453	4,443
1994	4,730	4,861	4,554	4,617	4,526	4,680	4,603	4,628	4,549	4,548	4,541
1995	4,585	4,780	4,579	4,635	4,535	4,675	4,605	4,665	4,585	4,579	4,566
1996	4,603	4,730	4,598	4,635	4,567	4,680	4,624	4,687	4,567	4,533	4,556
1997	4,786	4,585	4,591	4,639	4,540	4,673	4,607	4,687	4,538	4,531	4,536
1998	3,828	4,603	4,601	4,618	4,581	4,670	4,626	4,673	4,541	4,546	4,556
1999	4,137	4,786	4,647	4,628	4,614	4,667	4,641	4,678	4,604	4,611	4,609
2000	4,543	3,828	4,566	4,572	4,484	4,635	4,559	4,512	4,515	4,417	4,472
2001	4,115	4,137	4,486	4,550	4,392	4,617	4,504	4,570	4,420	4,395	4,403
2002	4,381	4,543	4,515	4,531	4,440	4,605	4,522	4,566	4,446	4,447	4,444
2003	4,715	4,115	4,497	4,515	4,338	4,582	4,460	4,408	4,341	4,357	4,346
2004	4,637	4,381	4,449	4,501	4,327	4,561	4,444	4,380	4,339	4,412	4,360
2005	4,421	4,715	4,442	4,510	4,377	4,571	4,474	4,538	4,430	4,530	4,446
2006	4,037	4,637	4,433	4,516	4,408	4,568	4,488	4,586	4,436	4,525	4,456
2007	4,447	4,421	4,416	4,504	4,406	4,565	4,485	4,572	4,427	4,503	4,446
2008	4,488	4,037	4,360	4,480	4,306	4,532	4,419	4,490	4,394	4,357	4,352
2009	4,534	4,447	4,326	4,486	4,279	4,527	4,403	4,506	4,426	4,401	4,369
2010	3,973	4,488	4,392	4,479	4,299	4,512	4,406	4,510	4,430	4,430	4,386
2011	4,144	4,534	4,432	4,459	4,370	4,510	4,440	4,528	4,442	4,462	4,425
2012	4,072	3,973	4,375	4,445	4,239	4,479	4,359	4,437	4,372	4,382	4,331

Table 4:

EASTERN

Out of sample forecast performance all available years (1990-2012)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.4%	10	10.1%	10	1.8%	3	57%	5	298	10	38	*9*
10-yr MA	5.7%	3	7.3%	4	2.6%	6	52%	1	92	8	22	*5*
20-yr MA	5.8%	6	7.8%	7	4.0%	8	65%	7	75	2	30	*7*
20-yr Trend	5.7%	2	7.1%	1	1.0%	1	43%	5	106	9	18	*3*
30-yr MA	6.2%	8	8.4%	8	5.0%	10	70%	10	70	1	37	*8*
50% 20-yr Trend / 50% 30-yr MA	5.7%	1	7.5%	6	3.0%	7	65%	7	86	6	27	*6*
de Bever	6.5%	9	8.4%	9	4.1%	9	65%	7	90	7	41	*10*
de Bever with Trend	5.7%	4	7.3%	3	2.0%	4	52%	1	83	4	16	*2*
Energy Probe	6.1%	7	7.4%	5	2.1%	5	52%	1	81	3	21	*4*
Average of de Bever with Trend, 20-yr Trend and Energy Probe	5.8%	5	7.2%	2	1.7%	2	48%	1	85	5	15	*1*

Table 5:

NIAGARA

Actual and Predicted Niagara weather zone Environment Canada Degree Days ('out-of-sample'), 1990 to 2012

Col. 1	*Col. 2*	*Col. 3*	*Col. 4*	*Col. 5*	*Col. 11*	*Col. 6*	*Col. 7*	*Col. 8*	*Col. 9*	*Col. 10*	*Col. 11*
Calendar Year	Actual	Naïve	10-yr MA	20-yr MA	20-yr Trend	30-yr MA	50/50	de Bever	de Bever with Trend	Energy Probe	Average of 10-yr MA, 50/50 and 20-yr Trend
1990	3,307	3,693	3,693	3,703	3,685	3,705	3,695	3,633	3,651	3,679	3,691
1991	3,343	3,845	3,697	3,721	3,686	3,711	3,698	3,683	3,733	3,827	3,694
1992	3,759	3,307	3,635	3,697	3,607	3,697	3,652	3,619	3,585	3,623	3,631
1993	3,878	3,343	3,596	3,681	3,526	3,687	3,607	3,582	3,462	3,464	3,576
1994	3,780	3,759	3,600	3,677	3,562	3,692	3,627	3,640	3,568	3,568	3,596
1995	3,703	3,878	3,623	3,699	3,576	3,693	3,635	3,688	3,661	3,670	3,611
1996	3,786	3,780	3,630	3,701	3,598	3,701	3,650	3,697	3,693	3,731	3,626
1997	3,669	3,703	3,635	3,711	3,571	3,693	3,632	3,705	3,705	3,727	3,613
1998	2,980	3,786	3,653	3,704	3,615	3,704	3,659	3,708	3,754	3,736	3,642
1999	3,338	3,669	3,676	3,701	3,612	3,699	3,656	3,694	3,740	3,710	3,648
2000	3,596	2,980	3,605	3,649	3,500	3,670	3,585	3,624	3,639	3,539	3,563
2001	3,239	3,338	3,554	3,626	3,453	3,665	3,559	3,613	3,577	3,492	3,522
2002	3,415	3,596	3,583	3,609	3,486	3,659	3,573	3,617	3,580	3,586	3,547
2003	3,799	3,239	3,573	3,584	3,423	3,645	3,534	3,585	3,475	3,531	3,510
2004	3,632	3,415	3,538	3,569	3,405	3,631	3,518	3,575	3,468	3,589	3,487
2005	3,653	3,799	3,530	3,577	3,464	3,642	3,553	3,626	3,547	3,657	3,516
2006	3,163	3,632	3,516	3,573	3,494	3,639	3,566	3,636	3,558	3,633	3,525
2007	3,296	3,653	3,511	3,573	3,521	3,644	3,583	3,650	3,547	3,664	3,538
2008	3,480	3,163	3,448	3,551	3,437	3,619	3,528	3,607	3,511	3,484	3,471
2009	3,565	3,296	3,411	3,544	3,368	3,604	3,486	3,576	3,490	3,414	3,422
2010	3,344	3,480	3,461	3,533	3,374	3,586	3,480	3,564	3,483	3,464	3,438
2011	3,458	3,565	3,484	3,519	3,422	3,578	3,500	3,572	3,481	3,513	3,469
2012	3,021	3,344	3,458	3,521	3,357	3,559	3,458	3,545	3,490	3,543	3,424

Table 6:

NIAGARA

Out of sample forecast performance all available years (1990-2012)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	9.0%	10	11.0%	10	1.9%	2	61%	5	246	10	37	*9*
10-yr MA	6.3%	1	8.2%	3	2.9%	4	52%	1	82	6	15	*2*
20-yr MA	6.4%	4	8.8%	5	4.5%	8	61%	5	72	4	26	*5*
20-yr Trend	6.6%	5	8.0%	1	1.2%	1	43%	4	98	8	19	*4*
30-yr MA	6.8%	6	9.3%	8	5.4%	10	65%	9	45	1	34	*8*
50% 20-yr Trend / 50% 30-yr MA	6.4%	3	8.4%	4	3.3%	5	52%	1	70	3	16	*3*
de Bever	6.8%	7	9.1%	6	4.6%	9	65%	9	49	2	33	*6*
de Bever with Trend	7.0%	8	9.2%	7	3.3%	6	61%	5	96	7	33	*6*
Energy Probe	7.0%	9	9.5%	9	3.9%	7	61%	5	107	9	39	*10*
Average of 10-yr MA, 50/50 and 20-yr Trend	6.4%	2	8.1%	2	2.5%	3	48%	1	82	5	13	*1*

c) Table 7 is reproduced here with the inclusion of the simple average of the three best individual methodologies for the Central region:

		20 yr Trend		10 yr MA		50/50 (30-yr MA & 20-yr Trend)		Average of 10-yr MA, 20-yr Trend and 50/50	
Test Year	Actual data to	rank	score	rank	score	rank	score	rank	score
1993	1991	1	10	4	23	5	24	3	17
1994	1992	1	12	6	27	4	21	3	18
1995	1993	3	21	4	22	2	16	4	22
1996	1994	2	19	5	23	2	19	4	22
1997	1995	5	23	6	26	2	18	3	20
1998	1996	5	30	4	23	3	20	2	17
1999	1997	8	35	3	24	2	19	2	19
2000	1998	2	20	3	21	2	20	1	19
2001	1999	2	18	2	18	1	17	1	17
2002	2000	3	20	2	17	1	15	1	15
2003	2001	2	14	4	18	3	15	1	12
2004	2002	1	10	3	18	3	18	2	15
2005	2003	2	16	1	15	3	17	1	15
2006	2004	4	18	1	15	3	17	2	16
2007	2005	4	19	1	16	3	18	2	17
2008	2006	1	15	2	17	3	20	1	15
2009	2007	1	15	2	17	3	20	1	15
2010	2008	2	18	2	18	3	19	1	15
2011	2009	4	21	3	18	2	17	1	16
2012	2010	2	18	3	20	2	18	1	14
2013	2011	2	18	3	19	4	20	1	13
2014	2012	2	16	3	19	4	20	1	13

As seen from the preceding tables reproduced, the average forecast from the top three methodologies ranked show higher scores than the individual component methodologies in each of the regions. As noted in Exhibit C2, Tab 1, Schedule 2, page 11, paragraph 20 the Company acknowledges that there are many more permutations that could potentially result in higher scores than what is shown here and what has been proposed. Testing the myriad of combinations is not feasible and not required given the approved evaluation framework.

The proposed 50:50 Hybrid methodology that equally weights the 20-year Trend and the 10-year Moving Average methodologies for the Central zone relies on the results of the evaluation framework that was approved by the Board in the selection of forecast methodologies used to forecast Board-approved degree days since EB-2006-0034. The purpose of the evaluation framework is to systematically apply consistent criteria to assess the accuracy of nine forecast methodologies, and to apply the results of the empirical findings to the selection of a single methodology.

In its original Rate Adjustment application for the 2013 Test Year (EB-2011-0354), the Company applied the approved evaluation framework to identify the highest ranking methodology. Using actual data to 2010, results of the analysis supported the continued use of the 20-year Trend methodology proposed. To update its evidence to include actual data to 2011, the Company again applied the evaluation framework which ranked the 10-year Moving Average methodology higher than the original 20-year Trend method. In an effort to validate long-term persistence, the Company sought to determine whether the 20-year Trend or the 10-year Moving Average was more consistently ranked highest over the comparable data sample.

Parties in the Settlement Agreement for EB-2011-0354 agreed to use the 10-year Moving Average. Since then, the evaluation framework was again employed to determine the forecast methodology for the Customized IR term, including actuals to 2012. Once again, the resulting methodology indicated a reversion to the 20-year Trend methodology. Given the five-year period in which the methodology would need to be in place within the Customized IR term and the consistent alternating selection of either the 20-year Trend and 10-year Moving Average methodologies using the evaluation framework, the Company sought to combine both proven methods equally. The resulting 50/50 Hybrid was then tested using the evaluation framework to evaluate its performance using the objective criteria established. Its higher score confirmed its improvement over the component methodologies which were each identified by the evaluation framework.

While the Company acknowledges that various combinations and permutations of the current methodologies assessed, as well as other methods, could result in marginally higher rankings, its proposal is guided by: (1) the approved evaluation framework, (2) the methodology (or methodologies) selected by the framework's application, and (3) the need for a forecast method that is easily understood and administered. The proposed 50/50 Hybrid combines the 20-year Trend and the 10-year Moving Average methodologies which were selected by the approved evaluation framework. The 50/50 Hybrid balances long-term weather dynamics and short-term volatility; the equal proportion recognizes the equal likelihood that one method could be preferred over the other during the course of the five year term on the basis of the most recent weather experience. Further, its component methodologies have been individually proven to perform consistently well over time for the Central region using the Board-approved evaluation framework.

Witnesses: H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #29

INTERROGATORY

Ref: Exhibit C2, Tab 1, Schedule 2

Please provide the analysis in Tables 1 through 6, but using only the last 10 years of actual data (i.e. 2003 to 2012) instead of the 1993 through 2012 period.

RESPONSE

Tables 2, 4, and 6 have been reproduced here. Data for the 2003 to 2012 period are included in Tables 1, 3, and 5 as originally filed.

Table 2:

CENTRAL
Out of sample forecast performance the last 10 years (2003-2012)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.6%	8	8.7%	8	1.0%	2	60.0%	3	200.27	9	30	8
10-yr MA	4.8%	1	6.7%	2	2.2%	5	70.0%	5	73.56	7	20	4
20-yr MA	5.7%	4	8.2%	7	5.3%	8	70.0%	5	46.39	3	27	7
20-yr Trend	5.5%	3	6.4%	1	1.2%	3	30.0%	5	42.87	1	13	1
30-yr MA	8.3%	9	10.4%	9	8.3%	9	100.0%	9	54.87	4	40	9
50% 20-yr Trend / 50% 30-yr MA	5.1%	2	7.1%	3	3.5%	7	70.0%	5	43.55	2	19	3
de Bever	6.3%	6	8.0%	6	3.1%	6	60.0%	3	68.61	5	26	6
de Bever with Trend	6.2%	5	7.5%	4	0.5%	1	50.0%	1	70.27	6	17	2
Energy Probe	6.6%	7	7.9%	5	1.4%	4	50.0%	1	87.66	8	25	5

Table 4:

EASTERN
Out of sample forecast performance the last 10 years (2003-2012)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	7.7%	9	9.1%	9	1.1%	2	40.0%	3	252	9	32	7
10-yr MA	5.2%	1	6.2%	2	1.8%	4	50.0%	1	50	5	13	1
20-yr MA	5.3%	3	6.9%	5	3.6%	7	60.0%	3	24	1	19	5
20-yr Trend	5.3%	4	6.0%	1	0.1%	1	40.0%	3	56	6	15	2
30-yr MA	5.7%	6	7.5%	7	4.8%	9	70.0%	8	34	2	32	7
50% 20-yr Trend / 50% 30-yr MA	5.2%	2	6.4%	3	2.4%	5	60.0%	3	41	4	17	4
de Bever	6.4%	8	7.9%	8	3.8%	8	70.0%	8	68	8	40	9
de Bever with Trend	5.5%	5	6.7%	4	1.7%	3	50.0%	1	40	3	16	3
Energy Probe	6.1%	7	7.1%	6	2.4%	6	60.0%	3	66	7	29	6

Witnesses: H. Sayyan
M. Suarez

Table 6:

NIAGARA
Out of sample forecast performance the last 10 years (2003-2012)

Col. 1	*Col. 2*	*C3*	*Col. 4*	*C5*	*Col. 6*	*C7*	*Col. 8*	*C9*	*Col. 10*	*C11*	*Col. 12*	*Col. 13*
	Accuracy				Symmetry				Stability			
	MAPE		RMSPE		MPE		Percent Overforecast		Standard Deviation		Score	Overall Rank
Naïve	8.5%	9	9.4%	9	1.0%	2	60.0%	2	204	9	31	6
10-yr MA	5.4%	1	6.8%	1	1.9%	3	50.0%	1	49	6	12	1
20-yr MA	5.7%	2	7.7%	5	3.7%	7	60.0%	2	24	1	17	3
20-yr Trend	5.8%	4	6.9%	2	0.0%	1	40.0%	2	54	7	16	2
30-yr MA	6.4%	7	8.7%	8	5.5%	9	70.0%	7	31	2	33	7
50% 20-yr Trend / 50% 30-yr MA	5.8%	3	7.3%	3	2.8%	5	60.0%	2	40	5	18	4
de Bever	6.5%	8	8.6%	7	4.9%	8	70.0%	7	34	4	34	9
de Bever with Trend	5.9%	5	7.6%	4	2.3%	4	60.0%	2	34	3	18	4
Energy Probe	6.1%	6	8.5%	6	3.6%	6	70.0%	7	85	8	33	7

Witnesses: H. Sayyan
M. Suarez

VECC INTERROGATORY #16

INTERROGATORY

ISSUE C24: Is the 2014 degree day forecast for each of the Company's delivery areas (EDA, CDA and Niagara) appropriate?

Evidence Ref: C2/T1/S2/ page 3, Table 1, "Actual and Predicted Central weather zone Environment Canada Degree Days ('out-of-sample'), 1990 to 2012"

a) Please provide all pre-1990 actual data (Col. 2) data used to prepare the referenced table.

RESPONSE

a) Please see Environment Canada degree days for the Central weather zone from 1942 to 1989 on the following page.

Witnesses: H. Sayyan
M. Suarez

Year	Environment Canada-Central Degree Days
1942	4041
1943	4453
1944	4113
1945	4283
1946	3792
1947	4153
1948	4125
1949	3810
1950	4163
1951	3978
1952	3836
1953	3622
1954	3957
1955	3890
1956	4181
1957	3895
1958	4051
1959	4025
1960	4013
1961	3943
1962	4105
1963	4125
1964	4168
1965	4359
1966	4263
1967	4310
1968	4309
1969	4291
1970	4309
1971	4166
1972	4572
1973	3947
1974	4236
1975	4005
1976	4475
1977	4181
1978	4485
1979	4236
1980	4384
1981	4146
1982	4187
1983	4066
1984	4144
1985	4106
1986	3987
1987	3765
1988	4076
1989	4250

Witnesses: H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #30

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix A

Please add a column to Tables 2 and 3 that reflects the most recent year-to-date normalized average uses available for 2013, along with the remaining months from the Board approved forecasts for 2013.

RESPONSE

The following Tables 2 and 3 provide an additional column of 2013 Forecast based on 2013 9-month actual normalized average use, along with 3-month Board approved forecasts for 2013.

Witnesses: R. Cheung
S. Qian

TABLE 2
GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED 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. 12	Col. 13	Col. 14
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 Board Approved Budget	2013 9&3	2014 Budget	2015 Forecast	2016 Forecast
Residential		2,815	2,745	2,682	2,666	2,632	2,594	2,548	2,512	2,496	2,488	2,515	2,433	2,412	2,392
	Change		(70)	(63)	(16)	(34)	(38)	(46)	(36)	(16)	(8)	19	(55)	(21)	(20)
	% Change		-2.49%	-2.30%	-0.60%	-1.28%	-1.44%	-1.77%	-1.41%	-0.64%	-0.32%	0.76%	-2.21%	-0.86%	-0.83%
Apartment		82,544	79,234	85,675	99,208	123,437	141,842	160,549	150,410	146,756	152,184	149,528	145,576	145,840	146,660
	Change		(3,310)	6,441	13,533	24,229	18,405	18,707	(10,139)	(3,654)	5,428	2,772	(6,608)	264	820
	% Change		-4.01%	8.13%	15.80%	24.42%	14.91%	13.19%	-6.32%	-2.43%	3.70%	1.89%	-4.34%	0.18%	0.56%
Commercial		17,078	16,688	16,623	17,038	17,872	18,539	18,946	19,374	19,489	19,667	19,912	19,346	19,376	19,426
	Change		(390)	(65)	415	834	667	407	428	115	178	423	(321)	30	50
	% Change		-2.28%	-0.39%	2.50%	4.89%	3.73%	2.20%	2.26%	0.59%	0.91%	2.17%	-1.63%	0.16%	0.26%
Industrial		51,232	52,178	53,945	58,775	73,753	88,297	105,297	108,745	105,108	108,598	105,942	105,840	106,690	107,680
	Change		946	1,767	4,830	14,978	14,544	17,000	3,448	(3,637)	3,490	834	(2,758)	850	990
	% Change		1.85%	3.39%	8.95%	25.48%	19.72%	19.25%	3.27%	-3.34%	3.32%	0.79%	-2.54%	0.80%	0.93%

* All historical average uses are on a calendar-year basis and have been normalized to the 2014 Budget degree days.

Witnesses: R. Cheung
S. Qian

TABLE 3
GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED 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. 12	Col. 13	Col. 14
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013 Board Approved Budget	2013 9&3	2014 Budget	2015 Forecast	2016 Forecast
Rate 1		2,815	2,745	2,682	2,666	2,632	2,594	2,548	2,512	2,496	2,488	2,515	2,433	2,412	2,392
	Change		(70)	(63)	(16)	(34)	(38)	(46)	(36)	(16)	(8)	19	(55)	(21)	(20)
	% Change		-2.49%	-2.30%	-0.60%	-1.28%	-1.44%	-1.77%	-1.41%	-0.64%	-0.32%	0.76%	-2.21%	-0.86%	-0.83%
Rate 6		21,213	20,717	20,986	22,209	24,797	26,704	28,548	28,910	28,664	29,204	29,170	28,383	28,366	28,420
	Change		(496)	269	1,223	2,588	1,907	1,844	362	(246)	540	506	(821)	(17)	54
	% Change		-2.34%	1.30%	5.83%	11.65%	7.69%	6.91%	1.27%	-0.85%	1.88%	1.77%	-2.81%	-0.06%	0.19%

* All historical average uses are on a calendar-year basis and have been normalized to the 2014 Budget degree days.

Witnesses: R. Cheung
S. Qian

ENERGY PROBE INTERROGATORY #31

INTERROGATORY

Ref: Exhibit C1, Tab 2, Schedule 1, Appendix A

a) Please confirm that Table 3 has normalized volumes all normalized to the 2014 test year degree day forecast.

b) What is driving the accelerated decrease in the Rate 1 average use in 2014 of -2.21% relative to the declines of -0.32%, -0.64% and -1.41% in the three previous years and the slower decreases shown for 2015 and 2016?

RESPONSE

a) Confirmed.

b) The average use decline in 2014 (Column 11) is calculated as the percentage change from the 2013 Board Approved Budget (Column 10). The 2013 Board Approved Budget was developed for an earlier proceeding and is underpinned by different driver variables than what is reflected in the 2014, 2015, and 2016 average use trend. As a result, the percentage change is not reflective of the average use trend.

   Using the same models as 2014 to 2016 for 2013 as well as actual data to 2012 and latest driver variables available when preparing the 2014 to 2016 budget, the 2013 Rate 1 average use forecast that is generated by these models is 2,463 m^3, or 25 m^3 lower than the 2013 Board Approved forecast of 2,488 m^3. As shown in the following table, the forecast decline in Rate 1 average use for 2014 is 1.22% below what current models have indicated for 2013. The rate of decline is consistent with the historical trend and does not demonstrate an accelerated decrease in average use.

Witnesses: R. Cheung
S. Qian
M. Suarez

TABLE 1
GENERAL SERVICE
SYSTEM-WIDE TOTAL NORMALIZED AVERAGE USE*

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
		2010	2011	2012	2013 Forecast	2014 Budget	2015 Forecast	2016 Forecast
Rate 1		2,548	2,512	2,496	2,463	2,433	2,412	2,392
	Change		(36)	(16)	(33)	(30)	(21)	(20)
	% Change		-1.41%	-0.64%	-1.32%	-1.22%	-0.86%	-0.83%

* All average uses are on a calendar-year basis and have been normalized to the 2014 Budget degree days.

Witnesses: R. Cheung
S. Qian
M. Suarez

ENERGY PROBE INTERROGATORY #32

INTERROGATORY

Ref: Exhibit C2, Tab 2, Schedule 1

a) Table 5 contains a number of equations that include variables that are not statistically significant at a 95% level of confidence. Please re-estimate the Rate 1 equations to eliminate all explanatory variables that are not statistically significant at the 95% level of confidence.

b) Please provide a table that shows the 2014 average use forecast for each of the equations in Table 5 based on the proposed equations and those estimated in part (a) above.

c) Please show how the various average use forecasts from each of the equations in Table 5 are combined to result in the 2014 forecast Rate 1 average use of 2,433 shown in Table 3 of Exhibit C1, Tab 2, Schedule 1, Appendix A.

d) Please provide a similar calculation if the average uses from the equations estimated in part (a) above were used. In particular, please provide the corresponding figure to 2,433 noted above in part (c).

RESPONSE

a) As stated at Exhibit C2, Tab1, Schedule 3, paragraph 15, “in any instance where insignificant variables were retained within the models, it was for the purposes of (1) improving the significance of other coefficients or (2) optimizing forecast accuracy.” Adding to that, theoretical relevance is also important. Excluding relevant variables can bias the coefficients of the explanatory variables. It is for this reason that natural gas prices are included in the residential models. Prices were only excluded when their inclusion made results less statistically valid (as experienced in NRC20 model).

The re-estimated results of the models with the exclusion of insignificant variables (at the 95% confidence level) from the long and short run equations are provided below. All variables which were not significant at the 95% level of confidence are removed from the models in a stepped fashion to follow the impact of its exclusion on the other variables’ coefficients significance and diagnostic test results. That way, if the removal of a variable caused other variables to become insignificant, those resultant effects cause the removal of the other variables.

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Metro Region Revenue Class 20:

1) LOG(REALCRCRPG) is removed from the original long run model. Results show that adjusted R-squared of models are lowered and DLOG(MET20VINT) and error correction mechanism (ECM_MET20(-1)) coefficients turned to be insignificant even at a 90% level of confidence through the exclusion of the gas price variable from the model. The re-estimated long and short run models are below:

Dependent Variable: LOG(MET20)
Method: Least Squares
Date: 11/20/13 Time: 10:52
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.440156	0.349365	6.984556	0.0000
LOG(CDD)	0.726010	0.043455	16.70697	0.0000
LOG(MET20VINT)	0.658551	0.046699	14.10217	0.0000
DUM2008	-0.059309	0.010681	-5.552992	0.0000

R-squared	0.986004	Mean dependent var	8.145933
Adjusted R-squared	0.984255	S.D. dependent var	0.128464
S.E. of regression	0.016120	Akaike info criterion	-5.285985
Sum squared resid	0.006236	Schwarz criterion	-5.095671
Log likelihood	78.00380	Hannan-Quinn criter.	-5.227804
F-statistic	563.6002	Durbin-Watson stat	1.176722
Prob(F-statistic)	0.000000		

Dependent Variable: DLOG(MET20)
Method: Least Squares
Date: 11/20/13 Time: 10:52
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.002625	0.004902	-0.535558	0.5974
DLOG(CDD)	0.762745	0.027359	27.87907	0.0000
DLOG(MET20VINT)	0.578889	0.405959	1.425979	0.1673
ECM_MET20(-1)	-0.230985	0.170600	-1.353953	0.1889

R-squared	0.973610	Mean dependent var	-0.015492
Adjusted R-squared	0.970168	S.D. dependent var	0.074937
S.E. of regression	0.012943	Akaike info criterion	-5.720569
Sum squared resid	0.003853	Schwarz criterion	-5.528593
Log likelihood	81.22768	Hannan-Quinn criter.	-5.663484
F-statistic	282.8527	Durbin-Watson stat	1.940882
Prob(F-statistic)	0.000000		

2) DLOG(MET20VINT) is removed from the short run model. Results show that (ECM_MET20(-1)) coefficient is still insignificant at a 90% level of confidence (which shows this model is not valid and cannot be used) and adjusted R-squared of model is also lowered through the exclusion of the vintage variable from the model. The re-estimated short run model is below:

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Dependent Variable: DLOG(MET20)
Method: Least Squares
Date: 11/20/13 Time: 13:08
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.008636	0.002555	-3.379579	0.0025
DLOG(CDD)	0.760979	0.027913	27.26230	0.0000
ECM_MET20(-1)	-0.258814	0.173091	-1.495251	0.1479

R-squared	0.971277	Mean dependent var	-0.015492
Adjusted R-squared	0.968884	S.D. dependent var	0.074937
S.E. of regression	0.013219	Akaike info criterion	-5.709925
Sum squared resid	0.004194	Schwarz criterion	-5.565944
Log likelihood	80.08399	Hannan-Quinn criter.	-5.667112
F-statistic	405.7895	Durbin-Watson stat	1.808704
Prob(F-statistic)	0.000000		

<u>Western Region Revenue Class 20:</u>

1) LOG(CENTEMP) is removed from the original long run model. Results show that adjusted R-squared of model is lowered. The re-estimated long and short run models follow:

Dependent Variable: LOG(WES20)
Method: Least Squares
Date: 11/20/13 Time: 13:15
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.235796	0.295426	7.568028	0.0000
LOG(CDD)	0.723978	0.036341	19.92154	0.0000
LOG(REALCRCRPG)	-0.067561	0.014723	-4.588878	0.0001
LOG(WES20VINT)	0.182654	0.018273	9.995827	0.0000
DUM2008	-0.062586	0.009914	-6.313151	0.0000

R-squared	0.989517	Mean dependent var	8.020676
Adjusted R-squared	0.987694	S.D. dependent var	0.121220
S.E. of regression	0.013447	Akaike info criterion	-5.619689
Sum squared resid	0.004159	Schwarz criterion	-5.381796
Log likelihood	83.67565	Hannan-Quinn criter.	-5.546963
F-statistic	542.7784	Durbin-Watson stat	1.183822
Prob(F-statistic)	0.000000		

Dependent Variable: DLOG(WES20)
Method: Least Squares
Date: 11/20/13 Time: 13:15
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.004673	0.002099	-2.226678	0.0365
DLOG(CDD)	0.726669	0.020377	35.66094	0.0000
DLOG(REALCRCRPG)	-0.073107	0.017709	-4.128172	0.0004
DUM2008	-0.013844	0.005374	-2.575864	0.0172
ECM_WES20(-1)	-0.528414	0.158437	-3.335176	0.0030

R-squared	0.984277	Mean dependent var	-0.013066
Adjusted R-squared	0.981418	S.D. dependent var	0.071980
S.E. of regression	0.009812	Akaike info criterion	-6.244841
Sum squared resid	0.002118	Schwarz criterion	-6.004871
Log likelihood	89.30535	Hannan-Quinn criter.	-6.173485
F-statistic	344.3041	Durbin-Watson stat	1.587955
Prob(F-statistic)	0.000000		

<u>Central Region Revenue Class 20:</u>

1) LOG(REALCRCRPG) is removed from the original long run model. Results show that adjusted R-squared of models is lowered, DLOG(CRC20VINT) is still insignificant, and DUM2008 became insignificant even at a 90% level of confidence through the exclusion of the gas price variable from the model. The re-estimation of long and short run models follow:

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Dependent Variable: LOG(CRC20)
Method: Least Squares
Date: 11/20/13 Time: 13:31
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.507884	0.290756	8.625394	0.0000
LOG(CDD)	0.710799	0.036174	19.64960	0.0000
LOG(CRC20VINT)	0.344875	0.016696	20.65631	0.0000
DUM2008	-0.047752	0.008812	-5.418857	0.0000

R-squared	0.991142	Mean dependent var	8.078922
Adjusted R-squared	0.990035	S.D. dependent var	0.135401
S.E. of regression	0.013516	Akaike info criterion	-5.638249
Sum squared resid	0.004385	Schwarz criterion	-5.447934
Log likelihood	82.93549	Hannan-Quinn criter.	-5.580068
F-statistic	895.1436	Durbin-Watson stat	1.307976
Prob(F-statistic)	0.000000		

Dependent Variable: DLOG(CRC20)
Method: Least Squares
Date: 11/20/13 Time: 13:31
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.001592	0.005149	-0.309279	0.7600
DLOG(CDD)	0.722722	0.027029	26.73840	0.0000
DLOG(CRC20VINT)	0.265372	0.186600	1.422144	0.1690
ECM_CRC20(-1)	-0.511210	0.211743	-2.414291	0.0245
DUM2008	-0.007332	0.006424	-1.141236	0.2660

R-squared	0.974193	Mean dependent var	-0.015596
Adjusted R-squared	0.969501	S.D. dependent var	0.072326
S.E. of regression	0.012631	Akaike info criterion	-5.739763
Sum squared resid	0.003510	Schwarz criterion	-5.499794
Log likelihood	82.48681	Hannan-Quinn criter.	-5.668408
F-statistic	207.6235	Durbin-Watson stat	2.033132
Prob(F-statistic)	0.000000		

2) DLOG(CRC20VINT) is removed from the short run model. Results show that DUM2008 is still insignificant and adjusted R-squared is also lowered through the exclusion of the vintage variable from the model. The re-estimated short run model is below:

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Dependent Variable: DLOG(CRC20)
Method: Least Squares
Date: 11/20/13 Time: 13:35
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.007828	0.002758	-2.838396	0.0093
DLOG(CDD)	0.719053	0.027498	26.14974	0.0000
ECM_CRC20(-1)	-0.616756	0.202671	-3.043138	0.0058
DUM2008	-0.007240	0.006565	-1.102869	0.2815

R-squared	0.971821	Mean dependent var	-0.015596
Adjusted R-squared	0.968145	S.D. dependent var	0.072326
S.E. of regression	0.012909	Akaike info criterion	-5.725889
Sum squared resid	0.003833	Schwarz criterion	-5.533913
Log likelihood	81.29950	Hannan-Quinn criter.	-5.668805
F-statistic	264.4028	Durbin-Watson stat	1.736209
Prob(F-statistic)	0.000000		

3) DUM2008 is removed from the short run model. Results show that the adjusted R-squared of model is also lowered through the exclusion of the dummy variable from the model. The re-estimated short run model is below:

Dependent Variable: DLOG(CRC20)
Method: Least Squares
Date: 11/20/13 Time: 13:36
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.009122	0.002507	-3.638422	0.0013
DLOG(CDD)	0.724391	0.027190	26.64185	0.0000
ECM_CRC20(-1)	-0.576739	0.200293	-2.879474	0.0082

R-squared	0.970331	Mean dependent var	-0.015596
Adjusted R-squared	0.967858	S.D. dependent var	0.072326
S.E. of regression	0.012967	Akaike info criterion	-5.748431
Sum squared resid	0.004035	Schwarz criterion	-5.604449
Log likelihood	80.60381	Hannan-Quinn criter.	-5.705617
F-statistic	392.4586	Durbin-Watson stat	1.711693
Prob(F-statistic)	0.000000		

<u>Northern Region Revenue Class 20:</u>

1) LOG(CENTEMP) is removed from the original long run model. Results show that adjusted R-squared of models are lowered and DLOG(REALCRCRPG) turned to be insignificant even at the 90% level of confidence. However LOG(NOR20VINT) became significant at the 95% confidence level through the exclusion of the employment variable from the model. The re-estimation of long and short run models follow on the next page:

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Dependent Variable: LOG(NOR20)
Method: Least Squares
Date: 11/20/13 Time: 13:50
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	2.502738	0.298033	8.397510	0.0000
LOG(CDD)	0.699527	0.036773	19.02304	0.0000
LOG(REALCRCRPG)	-0.085022	0.016129	-5.271329	0.0000
LOG(NOR20VINT)	0.201239	0.013130	15.32671	0.0000
DUM2009	-0.066973	0.011169	-5.996307	0.0000

R-squared	0.992471	Mean dependent var	8.081012
Adjusted R-squared	0.991162	S.D. dependent var	0.144489
S.E. of regression	0.013584	Akaike info criterion	-5.599459
Sum squared resid	0.004244	Schwarz criterion	-5.361565
Log likelihood	83.39242	Hannan-Quinn criter.	-5.526732
F-statistic	757.9769	Durbin-Watson stat	1.658194

Dependent Variable: DLOG(NOR20)
Method: Least Squares
Date: 11/20/13 Time: 13:50
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.002410	0.005715	0.421792	0.6773
DLOG(CDD)	0.697824	0.029864	23.36707	0.0000
DLOG(REALCRCRPG)	-0.043302	0.025892	-1.672387	0.1086
DLOG(NOR20VINT)	0.295345	0.123469	2.392058	0.0257
ECM_NOR20(-1)	-0.601026	0.226838	-2.649582	0.0146

R-squared	0.963152	Mean dependent var	-0.014924
Adjusted R-squared	0.956452	S.D. dependent var	0.069681
S.E. of regression	0.014541	Akaike info criterion	-5.458093
Sum squared resid	0.004652	Schwarz criterion	-5.218123
Log likelihood	78.68426	Hannan-Quinn criter.	-5.386737
F-statistic	143.7612	Durbin-Watson stat	2.191525
Prob(F-statistic)	0.000000		

2) DLOG(REALCRCRPG) is removed from the short run model. Results show that adjusted R-squared of model is lowered and LM test statistics is turned to be significant (which shows disturbances in the model are serially correlated) through the exclusion of the gas price variable from the model. The re-estimated short run model follows on the next page:

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Dependent Variable: DLOG(NOR20)
Method: Least Squares
Date: 11/21/13 Time: 06:43
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.005933	0.005516	1.075548	0.2933
DLOG(CDD)	0.698711	0.031003	22.53670	0.0000
DLOG(NOR20VINT)	0.370233	0.119473	3.098887	0.0051
ECM_NOR20(-1)	-0.653650	0.233255	-2.802300	0.0101

R-squared	0.958467	Mean dependent var	-0.014924
Adjusted R-squared	0.953050	S.D. dependent var	0.069681
S.E. of regression	0.015098	Akaike info criterion	-5.412492
Sum squared resid	0.005243	Schwarz criterion	-5.220516
Log likelihood	77.06864	Hannan-Quinn criter.	-5.355407
F-statistic	176.9268	Durbin-Watson stat	2.565204
Prob(F-statistic)	0.000000		

<u>Eastern Region Revenue Class 20:</u>

1) DLOG(REALCRCRPG) is removed from the original short run model. Results show that adjusted R-squared of models is lowered and DUM2008 became insignificant at the 95% level of confidence through the exclusion of the gas price variable from the model. The estimation of updated long and short run models follow:

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Dependent Variable: LOG(ERC20)
Method: Least Squares
Date: 11/21/13 Time: 07:00
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.400647	0.443223	3.160143	0.0044
LOG(EDD)	0.805379	0.053839	14.95890	0.0000
LOG(REALERCRPG)	-0.046481	0.018897	-2.459669	0.0218
LOG(ERC20VINT)	0.251629	0.018304	13.74701	0.0000
DUM2009	-0.075824	0.013148	-5.766735	0.0000

R-squared	0.987006	Mean dependent var	7.916900
Adjusted R-squared	0.984746	S.D. dependent var	0.137104
S.E. of regression	0.016933	Akaike info criterion	-5.158625
Sum squared resid	0.006595	Schwarz criterion	-4.920731
Log likelihood	77.22075	Hannan-Quinn criter.	-5.085898
F-statistic	436.7550	Durbin-Watson stat	1.788597
Prob(F-statistic)	0.000000		

Dependent Variable: DLOG(ERC20)
Method: Least Squares
Date: 11/21/13 Time: 07:00
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.007897	0.003414	-2.313141	0.0300
DLOG(EDD)	0.785514	0.037841	20.75838	0.0000
DUM2008	-0.015184	0.007962	-1.906907	0.0691
ECM_ERC20(-1)	-0.719981	0.223377	-3.223167	0.0038

R-squared	0.954485	Mean dependent var	-0.015582
Adjusted R-squared	0.948548	S.D. dependent var	0.069877
S.E. of regression	0.015850	Akaike info criterion	-5.315300
Sum squared resid	0.005778	Schwarz criterion	-5.123324
Log likelihood	75.75655	Hannan-Quinn criter.	-5.258215
F-statistic	160.7747	Durbin-Watson stat	2.371234
Prob(F-statistic)	0.000000		

2) DUM2008 is removed from the short run model. Results show that adjusted R-squared is lowered through the exclusion of the dummy variable from the model. The re-estimated short run model is below:

Dependent Variable: DLOG(ERC20)
Method: Least Squares
Date: 11/21/13 Time: 07:12
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.010753	0.003232	-3.327050	0.0028
DLOG(EDD)	0.792997	0.039650	19.99987	0.0000
ECM_ERC20(-1)	-0.659130	0.232912	-2.829951	0.0093

R-squared	0.947289	Mean dependent var	-0.015582
Adjusted R-squared	0.942896	S.D. dependent var	0.069877
S.E. of regression	0.016698	Akaike info criterion	-5.242594
Sum squared resid	0.006692	Schwarz criterion	-5.098612
Log likelihood	73.77501	Hannan-Quinn criter.	-5.199780
F-statistic	215.6551	Durbin-Watson stat	2.204379
Prob(F-statistic)	0.000000		

Niagara Region Revenue Class 20:

Niagara region models were not re-estimated because all variables in the model are significant at the 95% level of confidence.
b), c) and d)

The following tables show the re-run forecasts using the re-estimated models from part a) compared to the original forecasts from the models shown in the pre-filed evidence. For purposes of the interrogatory response, only Revenue Class 20 equations were re-estimated (represents 88% of Rate 1 customers); the results are shown in Table 1. Table 2 shows all revenue classes within Rate 1.

The Rate 1 average use is 2,435 m^3 using the original models. Using the re-estimated models, Rate 1 average use is 2,448 m^3. The resulting Rate 1 average use of 2,433 m^3 is obtained after adjusting for DSM.

Table 1:

Revenue Class 20 Regression Equations

	Metro Region	Western Region	Central Region	Northern Region	Eastern Region	Niagara Region
2014F- Original	2,719.1	2,411.1	2,187.3	2,500.8	2,055.2	2,093.0
2014F-Re-estimated (Enegy Probe 32 a)	2,718.9	2,403.8	2,209.2	2,509.7	2,128.9	2,093.0
Proportion of Unlocked Customers	25.3%	17.4%	10.5%	22.8%	16.0%	8.1%
2014F-Revenue Class 20-Original	2,403					
2014F-Revenue Class 20-Re-estimated	2,418					

Witnesses: R. Cheung
H. Sayyan
M. Suarez

Table 2:

Total Residential Revenue Classes

	RC10	RC20	RC50	RC60	RC61
2014F_Original	2,126.5	2,403.3	4,432.0	522.6	1,148.5
2014F-Re-estimated (Enegy Probe 32 a)	2,126.6	2,418.1	4,432.0	522.6	1,148.5
Proportion of Unlocked Customers	7.7%	88.1%	3.3%	0.2%	0.7%
2014F-Rate 1-Original	2,435				
2014F-Rate 1-Re-estimated	2,448				

Witnesses: R. Cheung
H. Sayyan
M. Suarez

ENERGY PROBE INTERROGATORY #33

INTERROGATORY

Ref: Exhibit C2, Tab 2, Schedule 1

Table 8 contains two industrial average use equations where the coefficients for degree days are not statistically significant at the 95% level of confidence.

What is the impact industrial average use forecast for 2014 of 105,840 shown in Table 2 of Exhibit C1, Tab 2, Schedule 1, Appendix A if the two noted equations are re-estimated to remove the degree day coefficients that are not statistically significant at the 95% level of confidence?

RESPONSE

In a manner similar to that provided in the response to Energy Probe Interrogatory #32 found at Exhibit I.C25.EGDI.EP.32, results of the re-estimated models are shown here in a stepped fashion as the exclusion of degree days from the Central and Eastern Revenue Class (“RC”) 73 models can affect the significance of other variables in the model.

Using the re-estimated models to forecast 2014 Central and Eastern RC 73 average use, the industrial average use forecast that is generated by these models is 10.2% lower than the original forecast of 105,840 m^3 (Table 2 of Exhibit C1, Tab 2, Schedule 1, Appendix A). The reduction in average use results from 1) the removal of the degree day variable from the Central and Eastern Revenue Class 73 models, 2) the removal of the GDP variable from the Central Revenue Class 73 model, and 3) the use of a single equation for Central Revenue Class 73 model (because the Error Correction model is not valid with the exclusion of degree day and GDP variables from the models).

Central Region Revenue Class 73:

1) LOG (CDD) for Central degree days is removed from the original long run and short run models. Re-estimated results show that the adjusted R-squared of the short run model is significantly lowered (from 0.83 to 0.63) and ONTGDP coefficients became insignificant in both equations at a 95% level of confidence with the exclusion of the degree day variable. The Ramsey Reset test result also became significant, which indicates that the model could be misspecified. The estimation of updated long and short run models are shown below:

Witnesses: H. Sayyan
M. Suarez

Dependent Variable: LOG(CRC73)
Method: Least Squares
Date: 11/21/13 Time: 13:11
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	7.581757	1.908311	3.973019	0.0006
LOG(TIME)	-0.130288	0.036921	-3.528830	0.0017
LOG(ONTGDP)	0.284443	0.153817	1.849226	0.0768
DUM2008	0.474521	0.042335	11.20865	0.0000

R-squared	0.876458	Mean dependent var	11.02743
Adjusted R-squared	0.861016	S.D. dependent var	0.190013
S.E. of regression	0.070838	Akaike info criterion	-2.325284
Sum squared resid	0.120432	Schwarz criterion	-2.134969
Log likelihood	36.55398	Hannan-Quinn criter.	-2.267103
F-statistic	56.75555	Durbin-Watson stat	1.959160
Prob(F-statistic)	0.000000		

Dependent Variable: DLOG(CRC73)
Method: Least Squares
Date: 11/21/13 Time: 13:11
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.026211	0.016007	-1.637509	0.1157
DLOG(ONTGDP)	0.658800	0.408116	1.614248	0.1207
DUM2008	0.285603	0.056798	5.028390	0.0000
DUM2009	-0.216251	0.059883	-3.611218	0.0015
ECM_CRC73(-1)	-0.879281	0.156316	-5.625037	0.0000

R-squared	0.689338	Mean dependent var	0.011173
Adjusted R-squared	0.632854	S.D. dependent var	0.085570
S.E. of regression	0.051849	Akaike info criterion	-2.915389
Sum squared resid	0.059143	Schwarz criterion	-2.675419
Log likelihood	44.35776	Hannan-Quinn criter.	-2.844034
F-statistic	12.20414	Durbin-Watson stat	2.355149
Prob(F-statistic)	0.000022		

2) LOG (ONTGDP) is removed from the long and short run models. Re-estimated results show that the model's adjusted R-square is lowered through the exclusion of the GDP variable from the model. The removal of degree days and GDP leaves the non-quantitative variables of a time trend as well as a dummy variable as the only explanatory variables in the model. As a result, the relationship cannot be modelled with Error Correction Models as the long and short run dynamics no longer apply. The re-estimated long and short run models are shown below for transparency although only the long-run model was used to reproduce the forecast:

Dependent Variable: LOG(CRC73)
Method: Least Squares
Date: 11/21/13 Time: 13:23
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	11.10974	0.045623	243.5124	0.0000
LOG(TIME)	-0.070953	0.019129	-3.709226	0.0010
DUM2008	0.502460	0.041417	12.13165	0.0000

R-squared	0.858856	Mean dependent var	11.02743
Adjusted R-squared	0.847564	S.D. dependent var	0.190013
S.E. of regression	0.074187	Akaike info criterion	-2.263507
Sum squared resid	0.137592	Schwarz criterion	-2.120771
Log likelihood	34.68910	Hannan-Quinn criter.	-2.219871
F-statistic	76.06183	Durbin-Watson stat	1.838814
Prob(F-statistic)	0.000000		

Dependent Variable: DLOG(CRC73)
Method: Least Squares
Date: 11/21/13 Time: 13:27
Sample (adjusted): 1986 2012
Included observations: 27 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-0.008499	0.012317	-0.690056	0.4971
DUM2008	0.280509	0.061808	4.538382	0.0001
DUM2009	-0.223076	0.067177	-3.320701	0.0030
ECM_CRC73(-1)	-0.742705	0.163556	-4.540978	0.0001

R-squared	0.598543	Mean dependent var	0.011173
Adjusted R-squared	0.546179	S.D. dependent var	0.085570
S.E. of regression	0.057645	Akaike info criterion	-2.733068
Sum squared resid	0.076428	Schwarz criterion	-2.541092
Log likelihood	40.89642	Hannan-Quinn criter.	-2.675983
F-statistic	11.43044	Durbin-Watson stat	2.154350
Prob(F-statistic)	0.000087		

Witnesses: H. Sayyan
M. Suarez

Eastern Region Revenue Class 73:

1) LOG (EDD) for Eastern degree days is removed from the original single equation model. Re-estimated results show that the Ramsey Reset test result became significant as with the Central model, indicating that the model could be misspecified. The re-estimated model is shown below:

Dependent Variable: ERC73
Method: Least Squares
Date: 11/25/13 Time: 07:02
Sample: 1985 2012
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-214240.5	45219.97	-4.737742	0.0001
DUM2003	70280.79	11789.83	5.961139	0.0000
DUM2004	-167512.7	15808.49	-10.59638	0.0000
DUM2009	108488.2	8277.268	13.10677	0.0000
EASTEMP	724.9562	98.39880	7.367531	0.0000
TIME	-6645.334	813.5870	-8.167945	0.0000

R-squared	0.960627	Mean dependent var	117329.3
Adjusted R-squared	0.951678	S.D. dependent var	50663.29
S.E. of regression	11136.92	Akaike info criterion	21.66133
Sum squared resid	2.73E+09	Schwarz criterion	21.94680
Log likelihood	-297.2586	Hannan-Quinn criter.	21.74860
F-statistic	107.3507	Durbin-Watson stat	2.184803
Prob(F-statistic)	0.000000		

Witnesses: H. Sayyan
M. Suarez

VECC INTERROGATORY #11

INTERROGATORY

ISSUE C25: Is the 2014 Average Use forecast appropriate?

Evidence Ref: C1/T2/S1/ pages 7-8, paragraph 16 and Figure 2, "Residential Normalized Average Use (m3)"

a) Does EGD agree that to the extent that newer homes are added as customers, the likelihood that there will be effects depressing residential average use due to replacing less efficient appliances and home improvements is not as great as nit would be if older homes were added as customers?

b) Please provide EGD's current best estimate as to 2013 actual normalized average residential use.

c) Please provide any elasticity estimates EGD has available with respect to the elasticity of residential gas consumption with respect to the gas supply charge.

RESPONSE

a) The Company disagrees. To the extent that newer homes are added as customers, the Company would expect new homes to have a stronger effect on reducing the overall residential average use than if older homes were added as new customers.

b) The current estimate of 2013 actual normalized average use for the residential sector based on nine months of actual data along with three months of forecast is 2,483 m^3.

c) The Company does not have elasticity estimates of consumption with respect to the gas supply charge, specifically. Proxy estimates of the elasticity of residential consumption to gas prices (as derived using all components of Rate 1 on a typical customer annual profile of 3064 m^3) can be obtained from the average use regression equations as shown in Exhibit C2, Tab 2, Schedule 1, pages 12 and 13. As the models are in logarithmic form, the coefficients for the real price of gas (REALCRCRPG, REALERCRPG) can be interpreted as the percentage change in average use for the region and revenue class resulting from a 1% change in real gas prices, all other variables constant. The relationship is negative as an increase in gas prices results in a reduction in average use consumption.

Witnesses: R. Cheung
S. Qian
M. Suarez

VECC INTERROGATORY #12

INTERROGATORY

ISSUE C25: Is the 2014 Average Use forecast appropriate?

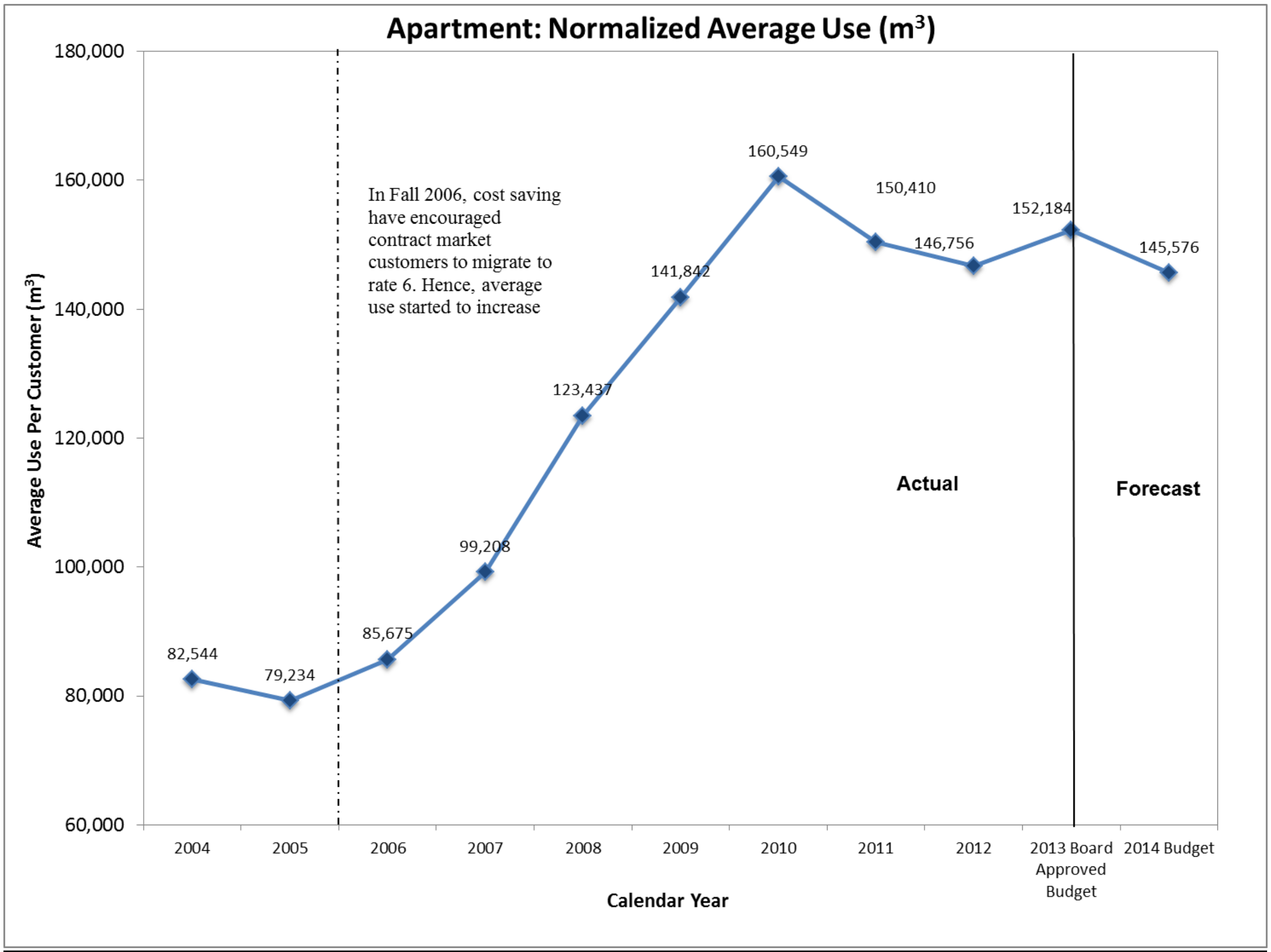
Evidence Ref: C1/T2/S1/ page 9, Figure 3, "Rate 6 Normalized Average Use (m3)"

a) Please provide a companion graph to the referenced figure that shows historical and forecast normalized average use for apartments only.

RESPONSE

The Figure on page 2 illustrates the normalized actual average use per customer for the Rate 6 apartment sector from 2004 to 2012 and the projection for 2013 to 2014, as filed at Table 2 of Appendix A of Exhibit C1, Tab 2, Schedule 1.

Witnesses: R. Cheung
S. Qian


Apartment: Normalized Average Use (m3)
Average Use Per Customer (m3)
180,000
160,000
140,000
120,000
100,000
80,000
60,000
In Fall 2006, cost saving have encouraged contract market customers to migrate to rate 6. Hence, average use started to increase
82,544
79,234
85,675
99,208
123,437
141,842
160,549
150,410
146,756
152,184
145,576
Actual
Forecast
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013 Board Approved Budget
2014 Budget
Calendar Year

VECC INTERROGATORY #13

INTERROGATORY

ISSUE C25: Is the 2014 Average Use forecast appropriate?

Evidence Ref: C1/T2/S1/ page 8, paragraph 16

a) Please provide details with respect to the rate switching from contract market customers to general service for each year 2006-2012, indicating the number of customers and the associated volumes which switched to general service from contract.

b) Can EGD confirm that no customers switched from Rate 6 to contract in the years 2006-2012? If not, please provide the number of customers and the associated volumes which switched from rate 6 to contract over this period.

RESPONSE

a) Table 1 and Table 2 on page 2 provide the matrix illustrating the volumes and the number of customers that have migrated among rate classes in 2007 compared to 2006. From the year of 2006 to 2007, there are 916 contract rate class customers with total volumes of 223.6 10^6m^3 who have migrated to Rate 6.

For the details about the rate switching from contract market to Rate 6 in the years 2007 to 2012, please refer to Tables 5 to 14 in response to APPrO Interrogatory #1, part (b) at Exhibit I.C23.EGDI.APPrO.1.

b) There are 21 contract rate class customers with total volumes of 9.8 10^6m^3 who have migrated from Rate 6 to contract in 2007 compared to 2006.

For the details about the rate switching from Rate 6 to contract in the years 2007 to 2012, please refer to Tables 5 to 14 in response to APPrO Interrogatory #1, part (b) at Exhibit I.C23.EGDI.APPrO.1.

Witnesses: R. Cheung
S. Qian

Table 1
Summary of Customer Migration: 2007 vs 2006
(Volumes in $10^6 m^3$)

Switch	Rate Class	To 6	100	110	115	125	135	145	170	TOTAL
From	6	x	6.9	0.2	0.0	0.0	0.0	2.7	0.0	**9.8**
	100	206.9	x	16.7	0.0	0.0	0.0	0.0	0.0	**223.6**
	110	14.6	9.1	x	4.5	0.0	0.0	0.0	0.0	**28.2**
	115	0.5	0.0	30.2	x	0.0	0.0	0.0	0.8	**31.5**
	125	0.0	0.0	0.0	0.0	x	0.0	0.0	0.0	**0.0**
	135	0.0	0.0	0.0	0.0	0.0	x	0.0	0.0	**0.0**
	145	10.8	5.8	0.0	0.0	0.0	1.8	x	0.0	**18.4**
	170	0.0	0.0	0.0	0.0	0.0	0.0	3.6	x	**3.6**
	TOTAL	**232.8**	**21.8**	**47.1**	**4.5**	**0.0**	**1.8**	**6.3**	**0.8**	

Table 2
Summary of Customer Migration: 2007 vs 2006
Number of Customers

Switch	Rate Class	To 6	100	110	115	125	135	145	170	TOTAL
From	6	x	16	1	0	0	0	4	0	**21**
	100	876	x	6	0	0	0	0	0	**882**
	110	23	5	x	1	0	0	0	0	**29**
	115	2	0	0	x	0	0	0	1	**3**
	125	0	0	0	0	x	0	0	0	**0**
	135	0	0	0	0	0	x	0	0	**0**
	145	15	4	0	0	0	1	x	0	**20**
	170	0	0	0	0	0	0	1	x	**1**
	TOTAL	**916**	**25**	**7**	**1**	**0**	**1**	**5**	**1**	

Witnesses: R. Cheung
S. Qian

VECC INTERROGATORY #14

INTERROGATORY

ISSUE C25: Is the 2014 Average Use forecast appropriate?

Evidence Ref: C1/T2/S1/ page 14 and Appendix A, Table 1, Forecast Accuracy

a) Does EGD agree that forecast accuracy should be measured by comparing the utility's ex ante forecast with the ex post actual?

b) Do the values shown in column 2 of Table 1reflect EGD's forecasts ex ante? If not, please provide a new column for this table that shows EGD's ex ante forecasts for each year.

RESPONSE

a) The determination of the appropriate forecast accuracy measure should be guided by the question or purpose which it informs. Based on the cited reference, the variance between an ex-ante forecast and an ex-post actual allows the Company to measure its projections against what actually occurred. The selection of this variance comparison provides a retrospective assessment.

In contrast, for the purpose of selecting the average use model’s specification based on the criterion of accuracy, the Company believes it is necessary to evaluate competing models based on the available information at the time of the forecast. At the time of the forecast, there is only a limited amount of information that is known, requiring reliance on other driver expectations to generate the forecast. The purpose in this case is a prospective assessment.

Pre-filed evidence at Exhibit C2, Tab 1, Schedule 3, page 4, paragraph 10 goes into the different sources of forecast uncertainty: model specification, forecast error from the driver variables used in the model, and structural breaks. To measure the forecast uncertainty that is driven by model specification, the Company uses comparisons of ex-post forecast and ex-post actual. To replicate conditions given the timing of typical regulatory applications, the Company also compares ex-ante forecast and ex-ante actual to measure errors from both model specification and driver variable forecasts, the latter of which is not under the Company’s control. Models that minimize both errors are considered more desirable than others.

b) Confirmed. Values in Column 2 are ex-ante forecasts for each year.

Witnesses: R. Cheung
S. Qian
M. Suarez

APPrO INTERROGATORY #5

INTERROGATORY

Reference: Exhibit D3 Tab 4 and EB-2011-0354 Exhibit D3 Tab 4 Schedule 1

Preamble: Paragraph 11 and 12 in the first reference illustrate that UAF volumes have been continuously increasing since 2002, and have increased from 0.6% in 2013 to the proposed 0.7% for 2014 (a 16.6% increase in UAF volumes). APPrO would like to better understand the relative impact of various factors that influence UAF and Enbridge's plans to further mitigate UAF.

The Company states in the second reference:

> *In summary, the Company either already embraces or has work in progress related to sixteen out of twenty steps identified from the industry benchmarking best practices in measuring, controlling the variability and managing the UAF. In some cases, the Company goes beyond the best practices and undertakes additional steps to minimize the measurement variations when possible.*

Issue: 26. Is the 2014 level of Unaccounted For ("UAF") volume appropriate?

Questions:

a) In light of statements made in EB-2011-0354 about meeting or exceeding best practices to manage UAF, please explain why UAF volumes are forecasted to increase by 16% from 2013 to 2014 (i.e. from 0.6% to 0.7%). Please include the major contributing factors to the increase.

b) Please provide the actual UAF as a percentage of throughputs for the years 2002-2012. Please include for reference purposes the percentage of UAF proposed for 2013 and projected percentage for each year of the Customized IR period.

c) Please list in order of descending order the top 5 factors contributing to UAF and an estimate of their relative contribution in percentage terms to the overall UAF.

d) Please discuss how each of these 5 factors is accounted for in the UAF Forecast Model.

e) Please discuss how varying heat content of gas supplies entering the Enbridge system is impacting the UAF volumes.

Witnesses: I. Chan
H. Sayyan
D. Small
M. Suarez

f) Please provide the weighted average monthly heating value of the gas entering the Enbridge system for the years 2008 to 2012. Please make these heating values available in an Excel spreadsheet capable of analysis upon request.

g) Please state the weighted average forecasted heat content assumption used to produce Enbridge's volume forecast in each of 2008 to 2013.

h) Please provide Enbridge's weighted average heat content used to produce Enbridge's volume forecast for each year of the Customized IR period.

i) In light of the proposed increase in UAF, what steps is Enbridge proposing to reduce UAF during the Customized IR period? Please provide the cost to implement each of these steps.

j) Please list the specific initiatives undertaken in each of 2012 and 2013 to reduce UAF, the cost to implement these initiatives and the estimated benefit.

k) Please confirm that potential losses (or gains) in unaccounted for volumes at Tecumseh storage, including metering differences at Dawn between Union and Tecumseh do not contribute to UAF distribution volumes.

l) Please confirm that fuel gas required to be supplied to Union and TransCanada to transport storage and other gas from Dawn to Enbridge's franchise do not form part of the UAF volumes.

<u>RESPONSE</u>

a) Table 4 of Exhibit D3, Tab 4, Schedule 1, illustrates that the Unaccounted for Gas ("UAF") volumes are forecast to increase by only 6% from the 2013 Budget of 73,092 10^3m^3 to 2014 of 77,660 10^3m^3. This change is due to moderate customer growth and is reflective of recent years' trends. In order to compare the year over year trend in UAF volumes, it is necessary to establish the UAF level expressed as percentage of total gas sendout. As illustrated in Table 1 on the next page, the 2014 Budget UAF, when expressed as a percentage of sendout, is not materially different from the historical actual trend.

Witnesses: I. Chan
H. Sayyan
D. Small
M. Suarez

Table 1
UAF% of Total Delivery Throughputs

	Fiscal Year ended September 30				Calendar Year ended December 31										
	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	Col. 15
Year	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013B***	**2014B**	**2015F****	**2016F-2018F****
%	-0.05%	0.24%	-0.33%	0.27%	0.09%	0.68%	0.37%	0.97%	0.66%	0.64%	0.71%	0.63%	0.69%	0.69%	0.69%

*Settlement Agreement filed in October 2012, Exhibit N1, Tab 1, Schedule 1, Appendix B, Page 2

**For the purpose of generating preliminary rate impacts for 2015 to 2018, Col. 14 and 15 represent preliminary forecasts here.

B denotes as Budget, F denotes as Forecast

b) Please refer to the Table 1 above.

c) By definition, the UAF volumes are not accounted for. As a result, the factors contributing to UAF and the corresponding relative contribution cannot be reliably explained, quantified, or estimated with any conventional statistical level of confidence.

As stated in EB-2011-0354, Exhibit D2, Tab 6, Schedule 1, page 2, UAF is the difference between the gas delivered into the distribution system being billed by the third party transmission pipelines (i.e., TransCanada Pipelines Limited, or TCPL, and Union Gas) and the gas measured out of the utility system. In other words, UAF represents the difference between metered gas deliveries (or sendout) and metered consumption of the Company's 2 million customers. Hence, there exist multiple factors impacting UAF simultaneously. Examples of these factors are metering differences, line leakage, unmetered uses and third party damage.

For the operational factors that the Company can manage or influence there exists programs and processes that are continuously being undertaken to enhance the measurement accuracy, to monitor the third party transmission pipelines custody transfer metering accuracy to ensure that their meters are within the +/-2% tolerance permitted by applicable agreement, to strengthen the metering process, to reduce leaks in the pipe, to decrease third party damages, to minimize any release to the atmosphere during normal maintenance operations, and to reduce unmetered uses.

Witnesses: I. Chan
H. Sayyan
D. Small
M. Suarez

Please refer to EB-2011-0354, Exhibit D2, Tab 6, Schedule 1, for a detailed discussion of these programs and processes.

As always, the Company will continue to invest in cost effective new technologies and processes to control variability and manage the amount of UAF for the factors that the Company can manage or influence. In particular, the operational factors mentioned above, such as leaks in the pipe or accidental damage to the pipe that the Company can manage or influence, also impact the distribution system's safety and reliability which is the Company's top priority. While it is difficult to quantify the impact of these operational factors on UAF for the reasons mentioned, the Company believes that the ongoing programs and initiatives that have been, and continue to be undertaken by the Integrity group are making a positive contribution. Please refer to the responses at i) and j) below.

There are some factors beyond the Company's control, such as metering variations from third party transmission pipelines and metering technology. To the extent that the third party transmission meters are inspected and certified to be within the mandated Measurement Canada standards and that any difference between custody transfer and check meters is within the industry tolerance level of +/-2%, the year over year variability or fluctuation of the UAF% is beyond the Company's control. Further, it is widely understood that gases are more difficult to measure than other concrete items, as the measured volume of gases are affected by temperature and pressure. Measurement Canada also observes that gas meter measurement is "a pretty complicated mechanism".[1]

d) As mentioned in part c), it is not possible to strip out and account for the contributing factors of unaccounted for gas. As a residual volume, it is by definition that which cannot be attributed to specific factors. The reliance on a model allows us to test the relationship of unaccounted for gas to other variables that can be quantified. For a number of years, the number of unlocked customers, which is a proxy for the size of the distribution system, has continued to show a high degree of correlation with UAF. Compared to models containing other variables, the forecast error was minimized by the use of unlocked customers in the model.

e) TCPL and Union Gas, and other third party transmission pipelines, invoice units transmitted using energy units (gigajoules (GJ)) rather than the volumetric units (cubic metres, (m^3)) as used by the Company to bill its 2 million customers. Accordingly, invoiced amounts from TCPL and Union have to be converted to cubic meters based upon the corresponding quality or heating value of the gas.

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[1] http://www.ic.gc.ca/eic/site/mc-mc.nsf/eng/lm03961.html

Depending upon the quality of gas acquired, the heating values can fluctuate on a daily basis and vary amongst different locations or sources.[2,3] Please also refer to response to c) above regarding how various factors can impact UAF volumes simultaneously.

f) Table 2 below provides the weighted average monthly heating value of the gas delivery sendout for the years 2008 to 2012.

Table 2

Weighted Average Monthly Heating Value (MJ/M³) of Gas Delivery Sendout

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Month	**2008**	**2009**	**2010**	**2011**	**2012**
January	37.59	37.80	37.60	37.71	37.77
February	37.61	37.65	37.64	37.71	37.76
March	37.59	37.58	37.58	37.66	37.77
April	37.42	37.55	37.62	37.79	37.80
May	37.31	37.42	37.61	37.66	38.14
June	37.39	37.40	37.69	37.76	38.26
July	37.40	37.43	37.62	37.70	38.41
August	37.41	37.49	37.63	37.71	37.91
September	37.39	37.45	37.68	37.98	38.07
October	37.58	37.56	37.65	37.69	38.39
November	37.71	37.62	37.70	37.69	38.07
December	37.89	37.58	37.76	37.72	38.16

g) 37.69 MJ/m³ for all years.

h) 37.69 MJ/m³ for all years.

i) Please refer to the responses to c) and d). Please also refer to EB-2011-0354, Exhibit D2, Tab 6, Schedule 1, for a detailed discussion of the programs and processes that have been, and are being, undertaken by the Company. Examples of specific programs undertaken in 2012, 2013 and during the IR period are further described below.

[2] http://www.transcanada.com/customerexpress/docs/assets/Gas_Quality_Specifications_Fact_Sheet.pdf and http://www.transcanada.com/customerexpress/2881.html
[3] http://www.uniongas.com/aboutus/aboutng/composition.asp

Witnesses: I. Chan
H. Sayyan
D. Small
M. Suarez

The program to replace cast iron and bare steel mains was completed in late 2012. It is expected this program will help reduce leaks and break failure rates of the Company's gas mains in the future.

As mentioned in evidence at Exhibit D1, Tab 17, Schedule 1, page 2, the Company's Damage Prevention sub-group within the Integrity group has been heavily involved with the development of regulations for Bill 8, the Ontario Underground Infrastructure Notification System Act, which was passed into law in June 2012. The purpose of this law is to require owners of underground infrastructures to become members of Ontario One Call by establishing a single organization to route all underground infrastructure locate requests in Ontario. Ontario is the first province to implement this mandatory system in Canada. This mandatory system exists in all 50 U.S. states, where damages rates are significantly lower than in Ontario. Given that almost[4] all of the damages to the Company's pipelines are caused by third party excavators, the passage of the law will help further reduce third party damages to the pipe progressively over the next few years[5].

The Company was also a founding member of the Ontario Regional Common Ground Alliance ("ORCGA") back in 2003. ORCGA is a nonprofit organization dedicated to shared responsibility in damage prevention and in the promotion of damage prevention Best Practices. ORCGA's mission is to enhance public safety and utility infrastructure reliability through a unified approach to effective and efficient damage prevention. Over the past several years, ORCGA has been recommending that the Ontario legislature pass the mandatory Ontario One Call legislation. In 2013, the Company was presented with an award for 10 years of support as a Gold Level sponsor. Figure 1 of Exhibit D1, Tab 17, Schedule 1, Page 8, illustrates that the Company has been successful in reducing total number of damages. There has been a 47% reduction in number of damages between 2003 and 2012.

In 2013, the Integrity group has budgeted an incremental amount of $2 million of O&M for in line inspection of the twin 30" XHP pipelines which run from Tecumseh to Dawn, and the 30" XHP pipeline which runs from Victoria Square to Station B. This is incremental O&M associated with new in line technology which will allow Enbridge to determine whether there are cracks in these lines which will also help reduce leaks in the pipe. This technology has only recently become available for natural gas lines, and is technology which probably could have identified the weld defect in the San Bruno, California pipe section which failed in September 2010. Please refer to EB-2011-0354, Exhibit D1, Tab 20, Schedule 1, for other specific initiatives undertaken by the Integrity group in 2013 along with the costs of implementing these initiatives to further reduce the incidents of leaks, damages, shut downs, and emergency repairs which can all give rise to UAF volumes.

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[4] Approximately 98%.

[5] Underground utility owners must become members of the mandatory Ontario One Call system by June 2013 and all municipalities with underground infrastructure are deemed to be members by June 2014.

Witnesses: I. Chan
H. Sayyan
D. Small
M. Suarez

Please refer to Exhibit D1, Tab 17, Schedule 1, pages 6 to 7, for the Company's costs and description in further enhancing the existing damage prevention programs, integrity inspections, and assessments on higher stress pipelines, corrosion and leak management programs during the next IR period which will help further to reduce leaks in the pipe and accidental damage to the pipe.

j) Please refer to response to i) above for examples of specific initiatives undertaken in each of 2012 and 2013. With respect to the cost to implement these initiatives and the corresponding estimated benefit, as stated in EB-2011-0354, Exhibit JT1.28, it is important to note that the Company has not tracked productivity benefits and costs on an initiative by initiative basis. The Company has proposed a performance measurement framework within this IR application to encompass the productivity initiatives reporting mechanism over the next IR term. Please refer to Exhibit A2, Tab 11, Schedule 2, for further details about the productivity initiatives reporting mechanism.

k) Confirmed. As explained in response to c) above, UAF is the difference between the gas delivered into the distribution system (city gate stations) being billed by the third party transmission pipelines (i.e., TransCanada Pipelines Limited, or TCPL, and Union Gas) and the gas measured exiting the utility system. Therefore, the volumes that go to Tecumseh storage for balancing purposes prior to delivering into the Company's distribution system or the Company's franchise area do not contribute to UAF.

l) Confirmed. Please refer to the response to k) above.

Witnesses: I. Chan
H. Sayyan
D. Small
M. Suarez

BOARD STAFF INTERROGATORY #68

INTERROGATORY

ISSUE C29: Is the overall change in Allowed Revenue reasonable given the impact on consumers?

Evidence Ref: A2/T3/S2/ Attachment B

Please provide the cumulative revenue impact of the incremental amounts sought for recovery over the 5-year duration of the 2014-2018 Customized IR Plan application relative to the Board-approved 2013 Revenue Requirement. Please translate this into a typical customer bill impact for the main rate classes.

Please indicate if the revenue inputs include the full known inputs of the GTA project and the TCPL settlement with the Eastern LDCs.

RESPONSE

The current 2014 to 2018 Allowed Revenue amounts in evidence include the impacts of the GTA project as shown in evidence at Exhibit C1, Tab 5, Schedule 1, Appendix A which at this time does not include impacts from the last updates in the GTA Leave-to-Construct ("LTC") application or the TCPL settlement. Please refer to Board Staff Interrogatory #43 at Exhibit I.A12.EGDI.STAFF.43 for an explanation of the process EGD proposes with respect to any final GTA LTC approvals.

Table A, provides the cumulative Allowed Revenue amounts proposed for recovery over the 2014 to 2018 period. Table B, shows the translated typical customer bill impacts.

Table A

Line No.	($millions)	Board Approved 2013	Fiscal Year 2014	Fiscal Year 2015	Fiscal Year 2016	Fiscal Year 2017	Fiscal Year 2018	Five Year Rate/Revenue Increase
1.	Revenue at existing rates	2,364.1	2,497.9	2,635.8	2,683.4	2,693.2	2,703.3	
2.	Other operating revenue	45.0	40.6	41.0	41.3	41.3	41.3	
3.	Total operating revenue	2,409.1	2,538.5	2,676.8	2,724.7	2,734.5	2,744.6	
4.	Revenue requirement:							
5.	Operating costs	2,078.6	2,187.1	2,356.9	2,423.3	2,446.2	2,468.7	
6.	Cost of capital	283.2	298.9	330.8	387.6	403.8	419.9	
7.	Income taxes	56.4	33.5	13.8	4.5	8.6	15.8	
8.	Taxes on (deficiency) / sufficiency	(4.5)	(9.3)	5.5	28.2	39.1	50.9	
9.	Customer care smoothing adjustment	(4.6)	(2.9)	(1.1)	0.8	2.9	5.0	
10.	Revenue requirement	2,409.1	2,507.3	2,705.9	2,844.4	2,900.6	2,960.3	
11.	Revenue (deficiency) / sufficiency	-	31.2	(29.1)	(119.7)	(166.1)	(215.7)	(499.4)

Table B **Sample Typical Customer Estimated Total Bill Impacts from 2013 to 2018**

	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
Line No.	**Rate class**	Annual Consumption m³	**2013 April QRAM Annual Total Bill $**	Change from 2013 April Q2 to 2014	**2014 Estimated Annual Total Bill $**	Change from 2014 to 2015	**2015 Estimated Annual Total Bill $**	Change from 2015 to 2016	**2016 Estimated Annual Total Bill $**	Change from 2016 to 2017	**2017 Estimated Annual Total Bill $**	Change from 2017 to 2018	**2018 Estimated Annual Total Bill $**	**Typical Customer Bill Impact 2013 to 2018**
1.	Rate 1	1,955	734	(2)	732	9	741	20	761	11	773	13	785	**51**
2.	Rate 1	2,480	867	(3)	864	12	876	26	902	15	917	16	933	**65**
3.	Rate 1	3,064	1,013	(4)	1,010	15	1,024	31	1,056	18	1,074	20	1,093	**80**
4.	Rate 6	22,606	6,283	(17)	6,266	55	6,322	151	6,472	99	6,572	106	6,678	**394**
5.	Rate 6	29,278	7,875	(21)	7,853	71	7,924	193	8,118	127	8,245	136	8,381	**506**
6.	Rate 6	43,285	11,089	(30)	11,060	100	11,160	265	11,425	176	11,602	188	11,790	**701**
7.	Rate 110	598,568	126,530	(445)	126,085	588	126,673	1,027	127,700	496	128,196	500	128,696	**2,167**
8.	Rate 110	9,976,121	1,994,627	(7,421)	1,987,206	8,549	1,995,755	14,929	2,010,684	7,206	2,017,890	7,271	2,025,160	**30,533**
9.	Rate 115	69,832,850	13,193,628	(3,638)	13,189,991	56,637	13,246,628	90,751	13,337,379	43,804	13,381,184	44,199	13,425,382	**231,754**
10.	Rate 145	339,188	70,700	21	70,721	319	71,040	617	71,657	270	71,927	272	72,199	**1,499**
11.	Rate 145	598,567	120,332	36	120,369	515	120,884	994	121,878	435	122,313	439	122,752	**2,419**
12.	Rate 170	9,976,120	1,725,284	(1,754)	1,723,530	4,621	1,728,151	8,808	1,736,959	3,688	1,740,648	3,714	1,744,362	**19,078**
13.	Rate 170	69,832,850	11,941,308	(12,276)	11,929,031	31,129	11,960,160	59,329	12,019,489	24,845	12,044,334	25,019	12,069,353	**128,045**

Witness: K. Culbert

APPrO INTERROGATORY #6

INTERROGATORY

Reference: Exhibit B2, Tab 10, Schedule 1, pages 41 to 49

Preamble: APPrO would like to better understand the XHP system, how it is defined by Enbridge and how it is used in the Cost Allocation Methodology

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

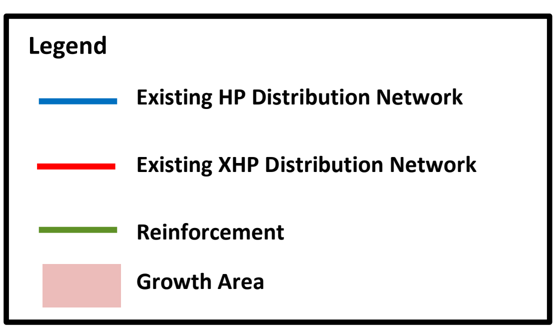
a) Please describe in detail what assets are included in the XHP system and include what is the minimum size and minimum pressure to qualify to be an XHP asset. Please state all pipe sizes that are included in XHP assets.

b) Please separately highlight on the system maps illustrated in the reference those gas mains that meet the XHP definition. Please also include pipe sizes and maximum allowable operating pressures.

RESPONSE

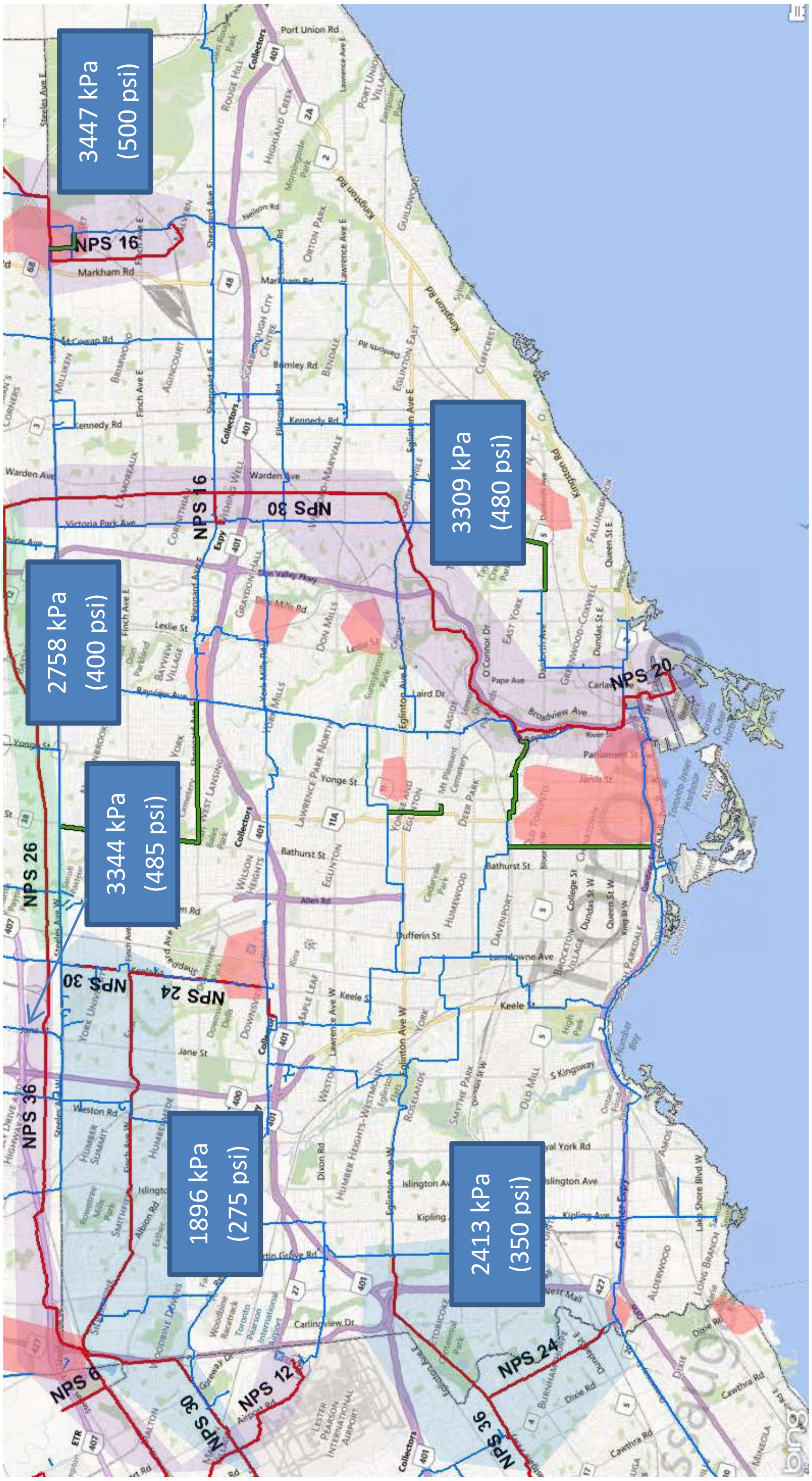
a) Pipes of any size which operate at a pressure greater than 1207 kPa (175 psi) are included in the XHP system.

b) Please see the maps on the following pages with XHP system as well as pipe sizes in inches. XHP MOP general areas are shaded and labeled.



Witnesses: L. Lawler
E. Naczynski

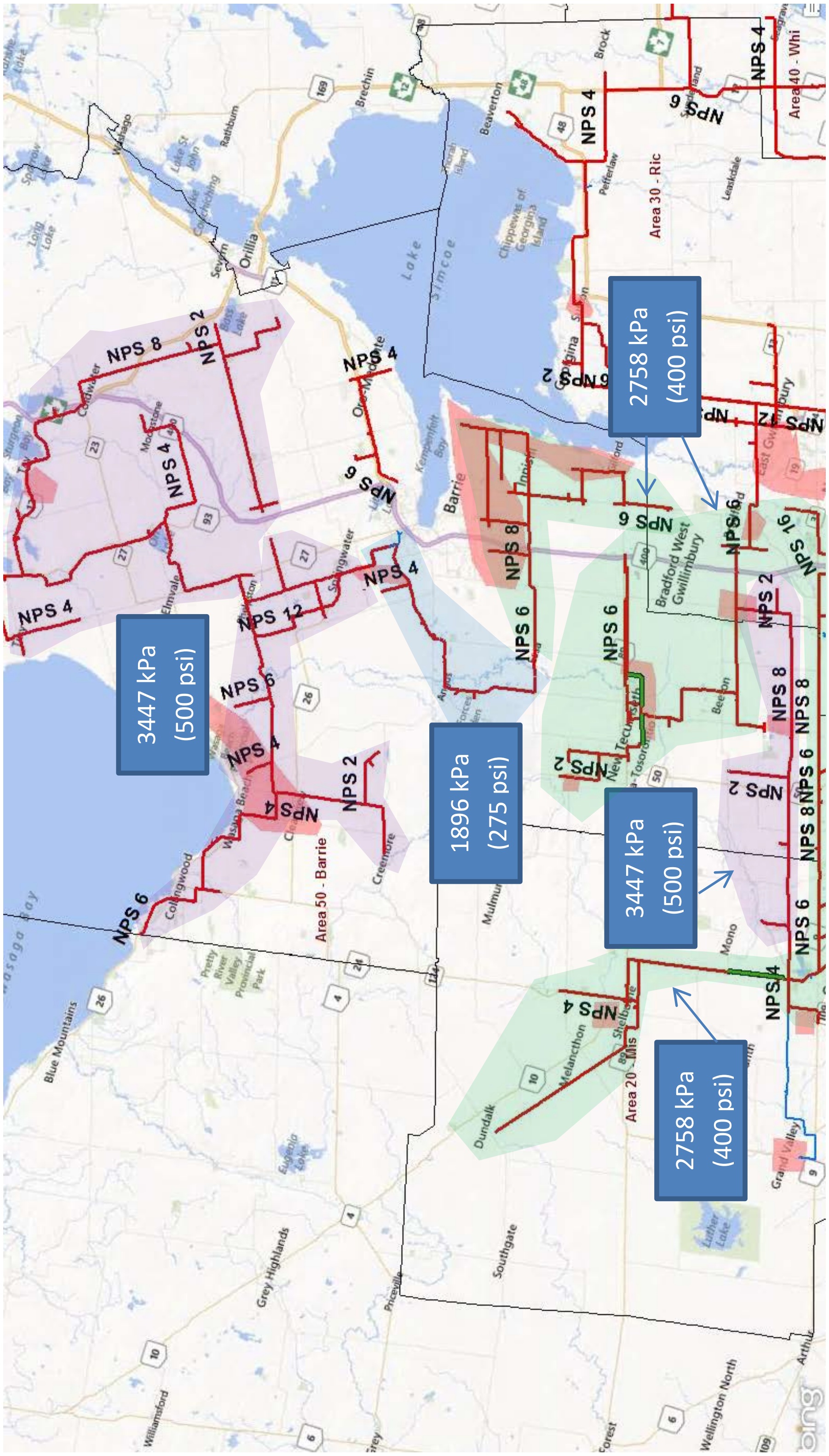
Filed: 2013-12-11
EB-2012-0459
Exhibit I.C30.EGDI.APPrO.6



Area 10 Reinforcements

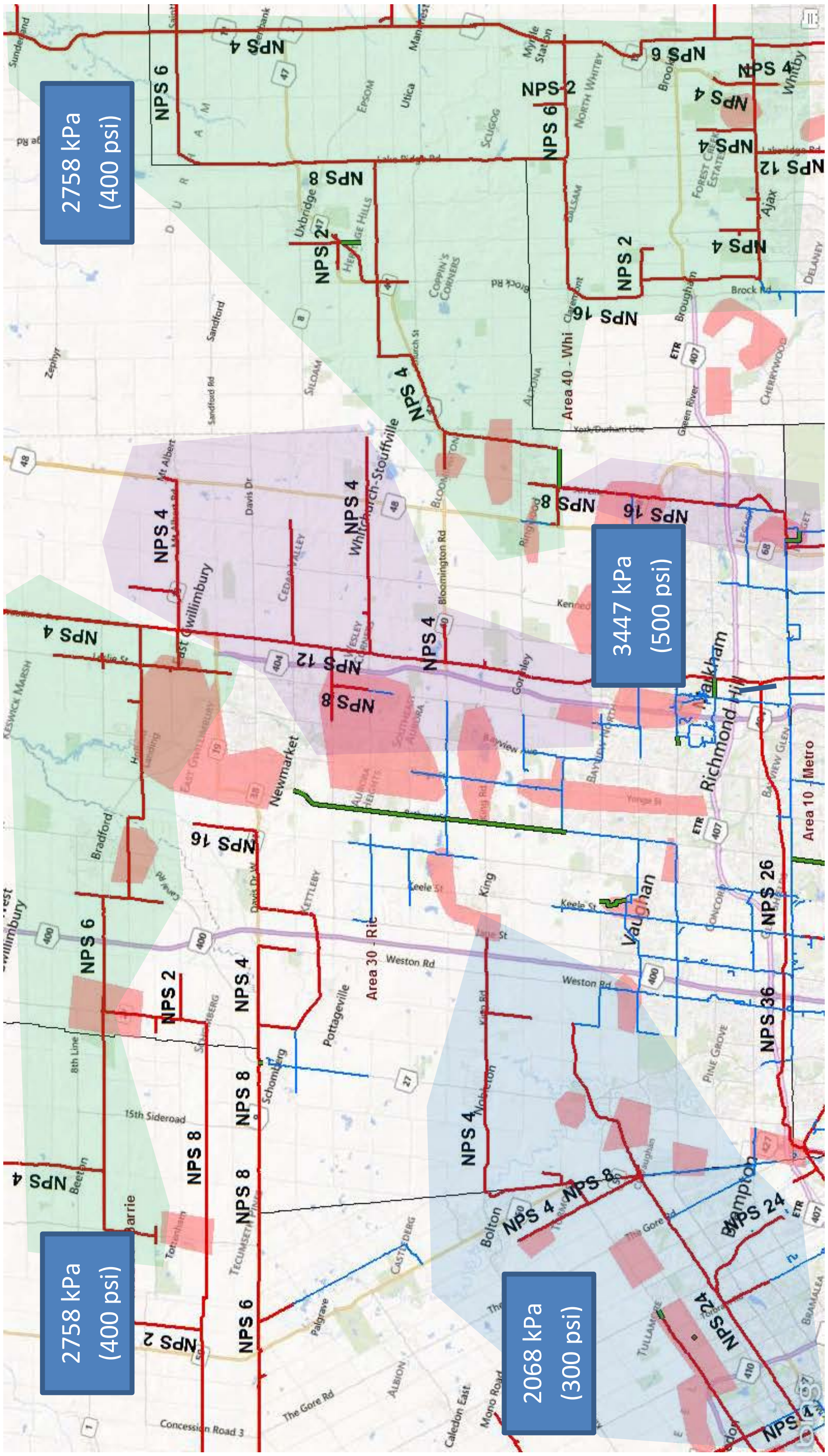
Witnesses: L. Lawler
E. Naczvnski

Area 20 and Area 50 Reinforcements

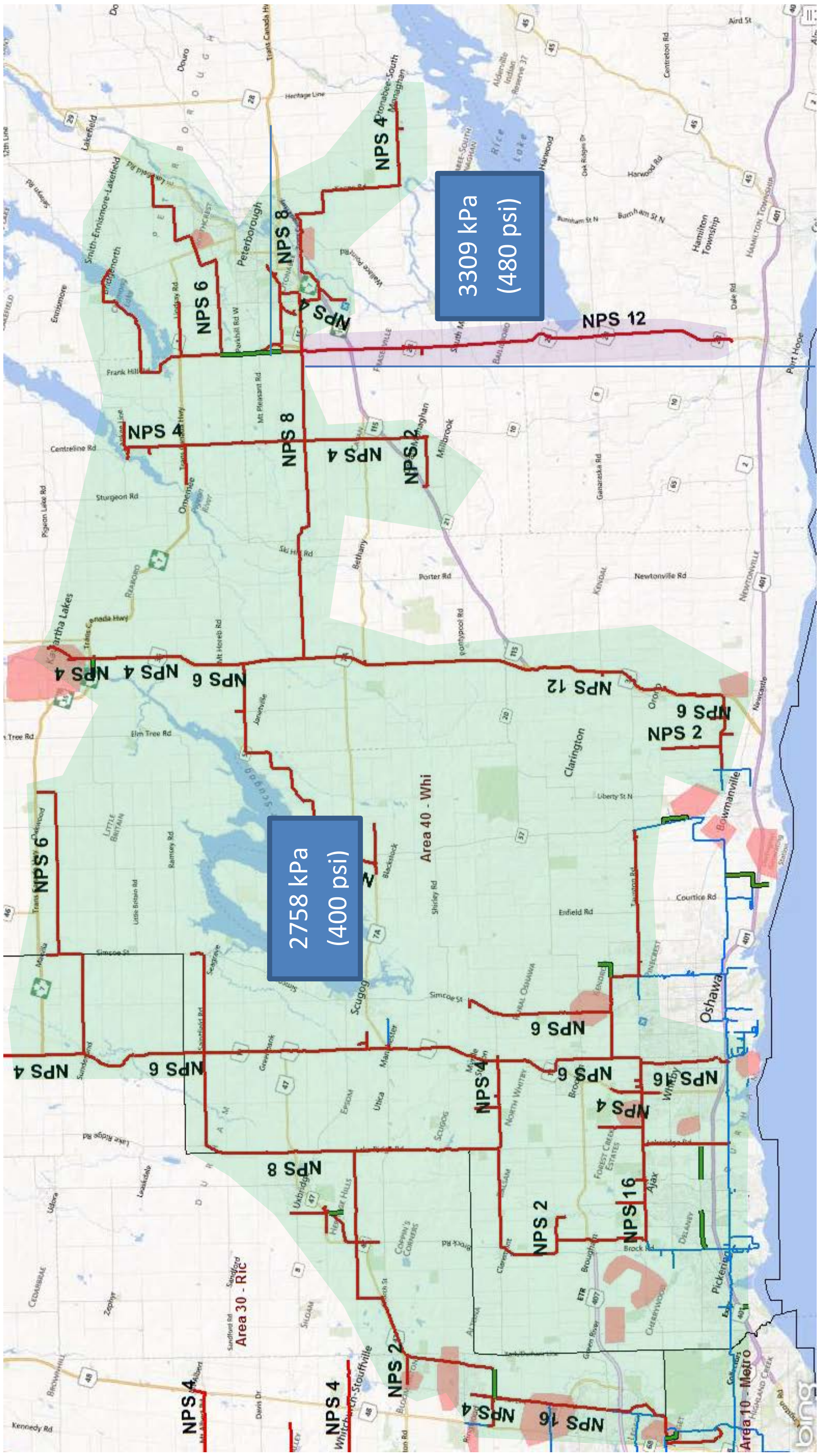


Witnesses: L. Lawler
E. Naczvnski

Area 30 Reinforcements

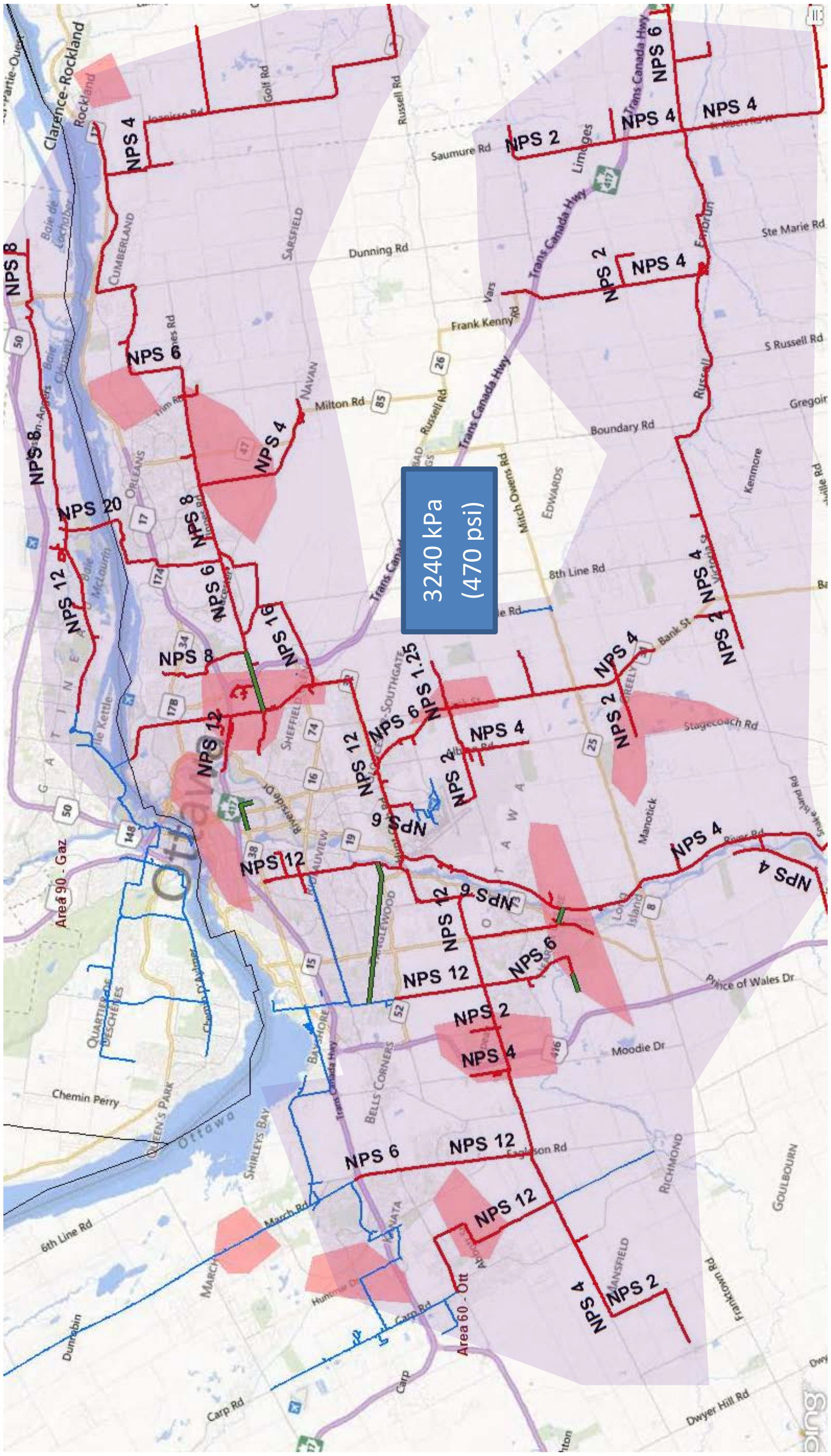


Witnesses: L. Lawler
E. Naczvnski



Area 40 Reinforcements

Witnesses: L. Lawler
E. Naczvnski



Area 60 Reinforcements

Witnesses: L. Lawler
E. Naczvnski

APPrO INTERROGATORY #7

INTERROGATORY

Reference: Exhibit G2, Tab 1, Schedule 1, page 25

Preamble: APPrO would like to better understand the TP Capacity definition used by Enbridge and how it is used in the Cost Allocation Methodology

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) Please provide a full definition of 'TP Capacity'

b) Please provide a description of how 'TP Capacity' is classified and allocated in Enbridge's Cost Allocation Methodology

RESPONSE

a) TP Capacity refers to pipeline capacity costs of the XHP system used to move gas from upstream transportation pipelines to the rest of the distribution grid. Pipes of any size which operate at a pressure greater than 1207 kPa (175 psi) are included in the XHP system.

b) The rate base and associated revenue requirement for mains is not derived on the basis of TP, High Pressure ("HP"), and Low Pressure ("LP") capacity, but instead follows the uniform system of accounts (for example, see Exhibit B5, Tab 1, Schedule 2, page 4, Line 9).

   In order to determine how much of these costs should be classified to TP Capacity, an analysis is performed where the length of main for each pressure class (TP, HP, and LP), material type (cast iron, steel, and plastic) and pipe diameter is used and the percentage of main by pressure class is calculated by material and diameter. This percentage is then multiplied by the capital investment summed by material and

Witnesses: A. Kacicnik
M. Kirk

diameter to determine the total capital investment by pressure class. The capital investment at the pressure level divided by the total capital investment determines the percentage of costs (such as mains costs) to be classified to TP, HP and LP capacity costs.

TP Capacity costs are allocated to rate classes based on the contribution of each rate class to the peak demand day, shown at Exhibit G2, Tab 6, Schedule 3, page 1, Line 2.1, and the corresponding allocation percentages are shown on page two, at Line 2.1.

APPrO INTERROGATORY #8

INTERROGATORY

Reference: Exhibit G2, Tab 4, Schedule 1

Preamble:

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) In Exhibit G2, Tab 4, Schedule 1 Page 1, row 4 Enbridge refers to ‘Distribution Reg.”. Please explain what this item is and how it relates to ‘TP Capacity’.

RESPONSE

a) Distribution Regulation costs are associated with the equipment that measures and regulates the flow of gas from upstream pipelines to the Company’s gas distribution system and within the system. Therefore, the classification of this item is based on the classification of distribution mains. Accordingly, distribution regulation costs are classified to TP, HP, and LP capacity.

Witnesses: A. Kacicnik
M. Kirk

APPrO INTERROGATORY #9

INTERROGATORY

Reference: Exhibit G2, Tab 1, Schedule 1

Preamble:

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) Are the costs of the regulator stations that reduce pressure between the XHP system and the downstream system, allocated to the XHP system or the downstream distribution system?

RESPONSE

Costs of regulator stations that reduce pressure between the XHP system and the downstream system are part of Distribution Regulation. Therefore, the classification of this item is based on the classification of distribution mains. Accordingly, distribution regulation costs are classified to TP, HP, and LP capacity.

Witnesses: A. Kacicnik
M. Kirk

APPrO INTERROGATORY #10

INTERROGATORY

Reference: Exhibit G2, Tab 1, Schedule 1, page 4

Preamble:

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) Does Enbridge agree that the Cost Allocation Methodology is based on the cost causality principle and that customer classes should only be allocated the share of costs that they impose on Enbridge's system? If not, please explain why not.

b) Given the peak flow that typically or on average exists in a XHP system (for a system that includes a Rate 125 customer along with other customer volumes), what minimum pipe size would be capable of reasonably serving an embedded Rate 125 customer along with other customers' loads? Please provide a complete explanation.

c) Based on the responses to the questions above:
   i. Please provide the XHP rate bases by size and maximum pressure range
   ii. Please identify the specific assets and the value of the XHP rate base and expenses that are reasonably capable of serving Rate 125 customers (or do serve those Rate 125 customers on dedicated pipelines) from the remaining XHP assets and expenses included in Enbridge's Cost Allocation Methodology reflecting the reasonable minimum size and pressure required to meet the criteria to be grouped as a rate 125 customer.
   iii. Based on the response to part b), re-run Enbridge's Cost Allocation Model filed in this proceeding for the period 2014 to 2018 by allocating to rate 125 customers only those XHP system assets that are reasonably capable to supply service to them and provide the results of the model run in the same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule 1.

Witnesses: A. Kacicnik
M. Kirk

iv. Based on the results of c) above please provide the rates and proposed rate increases to all customer classes for the years 2014, 2015, 2016, 2017 and 2018.

d) Please provide a live Excel model of Enbridge's Cost Allocation Methodology

RESPONSE

a) Yes, Enbridge agrees and notes that the Board approved postage stamp rate making methodology accomplishes that goal.

b) The minimum pipe size capable of serving an embedded Rate 125 customer is 6 inches in diameter. A 4 inch diameter pipeline could provide service in limited circumstances only. Consequently, XHP pipes with diameter of 4 inches or less have been removed from the XHP assets in the responses to part c) ii., iii., and iv. below.

c)

i. The following table shows the length and cost for XHP pipelines by diameter (as noted in the response to APPrO #6 and elsewhere pipes of any size which operate at a pressure greater than 1,207 kPa (175 psi) are part of the XHP system):

Pipelines Included in XHP System

Pipe Diameter (inches)	Pipe Length (m.)	Total $
1.50	40,046.70	3,972,015.54
2.00	222,666.80	5,323,607.95
3.00	1,683.60	87,000.03
4.00	977,592.50	64,868,976.40
6.00	606,090.40	58,150,663.23
8.00	671,086.30	72,805,142.10
10.00	0.00	0.00
12.00	270,547.00	56,665,561.79
16.00	77,402.30	60,110,825.57
20.00	11,049.00	4,103,700.56
24.00	56,214.90	97,486,546.58
26.00	14,328.20	2,945,650.02
30.00	66,034.80	45,237,725.20
36.00	63,129.80	85,618,821.91
Total XHP Pipe	3,077,872.30	557,376,236.88

Witnesses: A. Kacicnik
M. Kirk

ii. As stated in part b) of this response, the minimum pipe size capable of serving an embedded Rate 125 customer is 6 inches in diameter.

The table from the response c) i. is reproduced below, excluding pipe with diameter 4 inches and below.

Pipelines Included in XHP System

Pipe Diameter (inches)	Pipe Length (m.)	Total $
6.00	606,090.40	58,150,663.23
8.00	671,086.30	72,805,142.10
10.00	0.00	0.00
12.00	270,547.00	56,665,561.79
16.00	77,402.30	60,110,825.57
20.00	11,049.00	4,103,700.56
24.00	56,214.90	97,486,546.58
26.00	14,328.20	2,945,650.02
30.00	66,034.80	45,237,725.20
36.00	63,129.80	85,618,821.91
Total XHP Pipe	1,835,882.70	483,124,636.96

iii. and iv. The following table summarizes the impact of not allocating costs associated with XHP mains of 4 inches in diameter and below to Rate 125 customers for each year in the 2014 to 2018 period. For simplicity of the response the table below shows the impact on Rate 125 only as impacts on the other customer classes would be minor.

The amount of 2014 Capacity TP allocation referred to in the table is the sum of Line Item 4.1 of Exhibit G2, Tab 5, Schedule 2, page 1 and Exhibit G2, Tab 5, Schedule 3, page 1.

Witnesses: A. Kacicnik
M. Kirk

	Capacity TP Allocated to Rate 125	
	As Proposed ($millions)	**Excluding <= 4 inch ($millions)**
2014	9.96	9.02
2015	10.40	9.40
2016	11.63	10.47
2017	12.07	10.98
2018	12.55	11.28

The Company notes that this approach would also affect the level of site restoration cost refund to be allocated to Rate 125 customers. The associated impact in 2014 is approximately $100 thousand (as proposed, the site restoration cost refund is approximately $759 thousand, while excluding mains 4 inches in diameter and below results in a site restoration cost refund of approximately $659 thousand).

d) The Company respectfully declines to provide a live model of its Cost Allocation Methodology. However, the Company can respond to questions, provide clarifications and perform scenarios that would benefit APPrO's understanding of issues relevant to this proceeding.

Witnesses: A. Kacicnik
M. Kirk

APPrO INTERROGATORY #11

INTERROGATORY

Reference: Exhibit B2, Tab 3, Schedules 1 and 2

Preamble: APPrO would like to understand the need for the Ottawa Reinforcement, the GTA Reinforcement, the Allison Reinforcement, the Harmony Conlin Reinforcement and the York Region Reinforcement Project and the impact of these and other reinforcement projects on Rate 125 customers based on Enbridge's Cost Allocation Methodology. APPrO is using the term Advance Capacity to mean that portion of XHP distribution capacity that is being added as a result of a reinforcement project that will not be used in the test year. The Advance Capacity that is being added is usually the result of economies of scale of pipeline construction and based on a long term market forecast for an area.

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) With regard to reinforcement projects or other new XHP projects:
   i. Please explain how the costs of providing the Advance Capacity have been allocated to rate classes in Enbridge's Cost Allocation Methodology.
   ii. For each of the 5 above noted reinforcement projects please provide:
      1. The market growth additions by rate class for the 2015 to 2025 period, or the projection period specified in the respective facility applications
      2. The peak hour and peak day capacities that are being added.
      3. The Advance Capacity that will exist in each project in each of 2014, 2015, 2016, 2017, and 2018.
   iii. Please confirm that the effect of the current allocation methodology is that the annual costs of this Advance Capacity is borne by all rate classes, including Rate 125, in proportion to the allocator until such time as the test year market demand grows to the point such that it equals the capacity that was added.
   iv. Please provide Enbridge's views on the appropriateness of allocating the cost of this Advance Capacity only to the respective rate classes requiring such growth from the in-service date of the Advance Capacity, rather than the projected year that such Advance Capacity will be utilized.

Witnesses: A. Kacicnik
E. Naczynski

v. Please provide the amount of Advance Capacity that exists (or is being proposed) by system in all other XHP systems not referred to in this question (see maps illustrated in Exhibit B2 Tab10 Schedule 1 pages 41-49)

vi. Please explain how the Ottawa Reinforcement Project enhances security of supply and provides operational flexibility.

b) Re-run Enbridge's Cost Allocation Model filed in this proceeding for the period 2014 to 2018 by allocating the costs of Advance Capacity to those distribution customers that directly benefit from the use of such Advance Capacity and provide the results of the model run in the same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule 1.

c) Based on the results above please provide the rates and proposed rate increases to all customers for the years 2014, 2015, 2016, 2017 and 2018

RESPONSE

a)

i. While the Company does not agree with the characterization of advanced capacity, the following provides a description of how the Company's test year revenue requirement is allocated to the various customer classes and recovered in rates.

The Company's cost allocation methodology allocates the test year revenue requirement to the customer classes acting as a guide to rate design. Once a pipeline is put into service the associated annualized costs (i.e., the annual revenue requirement that the pipeline in question would became a part of) will be recovered in the test year from the customer classes applying the Board approved cost allocation and rate design methodologies. The cost of the XHP system is recovered from the customer classes based on the Delivery Demand TP allocator, which is discussed in the response to APPrO Interrogatory #14 at Exhibit I.C30.EGDI.APPRO.14.

ii.

1. The forecast market growth additions in the noted projects were all considered to be general service customers (i.e., Rate 1 and Rate 6 customers). Although the forecast assumed general service customers, it is probable some of the growth will be realized through contract rate customers. However, the Company did not have a forecast of contract rate customers at the time the projects were developed. For the forecast of

market growth additions for the GTA project and Alliston project, please see EB-2012-0451, Exhibit A, Tab 3, Schedule 4, page 4 and EB-2011-0323, Exhibit A, Tab 3, Schedule 1, page 2, respectively.

2. Please see the response to APPrO Interrogatory #13 c) at Exhibit I.C30.EGDI.APPRO.13.

3. Please see the response to APPrO Interrogatory #13 c) at Exhibit I.C30.EGDI.APPRO.13.

iii. The Company confirms that the total test year Board approved revenue requirement is recovered in the test year. The cost of the XHP system is recovered from the customer classes based on the Delivery Demand TP allocator, which is discussed in the response to APPrO Interrogatory #14 at Exhibit I.C30.EGDI.APPRO.14.

iv. The Company does not agree with the characterization of advanced capacity and notes that its system expansion and reinforcement projects conform to the EBO 188 guidelines for system expansion. Accordingly, system expansion and reinforcement projects are planned and carried out in a manner such that timing and economies of scale in pipeline installation and meeting customer growth are optimized.

Although the Company does not endorse this approach, another approach to meet customer growth would be to expand or reinforce the system by installing just enough pipeline capacity to meet the needs of the customers in the test year. This approach would result in higher costs, and consequently higher customer bills, than the approach based on the EBO 188 system expansion guidelines.

Further, the Company's rates are designed to recover the test year revenue requirement of an integrated system. The use of postage stamp rates in such an integrated system is supported by the costing of each service at the customer class average. This approach to setting rates does not differentiate between specific investments or the mix of investment vintages. In the Company's view it would be inappropriate to deviate from the established approach. If changes were to be made to the postage stamp rate making, proposed changes would need to be evaluated on a comprehensive basis rather than only on the basis of treatment of specific investments.

Witnesses: A. Kacicnik
E. Naczynski

v. Please see the response to APPRO Interrogatory #13 c) at Exhibit I.C30.EGDI.APPRO.13.

vi. The security of supply is enhanced as the take away capability at Richmond Gate opens a supply path to better manage flows between Ottawa Gate and Richmond Gate. Operational flexibility is provided by reducing the dependency of a single delivery point.

b) and c) Please see the response to APPrO Interrogatory #13 at Exhibit I.C30.EGDI.APPRO.13.

Witnesses: A. Kacicnik
E. Naczynski

APPrO INTERROGATORY #12

INTERROGATORY

Reference: Exhibit B1 Tab2 Schedule 1

Preamble: APPrO would like to understand Enbridge's customer connection policy

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) With respect to Enbridge's customer connection policy:
   i. Please confirm that all new Rate 125 customers must undergo an economic feasibility study to evaluate the costs and revenues that will be realized to serve the new customer
   ii. Please confirm that all costs for new Rate 125 customers are incorporated in the economic analysis including the costs of adding the full capacity in the XHP system (as opposed to just the incremental XHP capacity required to serve the customer)
   iii. Please confirm that in the event that the Profitability Index of the economic feasibility is <1.0, that the customer is required to pay a contribution in aid of construction by an amount that results in the Profitability Index being raised to 1.0.
   iv. Which other rate classes include the incremental costs of adding XHP system capacity when a new customer from that class undergoes an economic feasibility analysis prior to being serviced?
   v. Please confirm that Enbridge is required to maintain a rolling Profitability Index =1.1 to take into account the periodic costs of adding XHP system capacity. If not confirmed, please explain.

RESPONSE

a)

i. It is confirmed that all new Rate 125 customers must undergo an economic feasibility assessment as prescribed under EBO 188.

Witnesses: F. Ahmad
I. MacPherson

ii. All incremental costs to serve the customer and revenues from the customer are incorporated in the economic feasibility analysis of new Rate 125 customers as per the Board’s guidelines prescribed in EBO 188.

iii. In the event that the Profitability Index (“PI”) of the economic feasibility is <1.0 for a new Rate 125 customer, the customer is required to pay a contribution in aid of construction by an amount that results in the PI being raised to 1.0.

iv. Whenever an economic feasibility analysis is required for a new customer (in any rate class), the Company takes into account all incremental costs and revenues associated with that customer, as per the Board’s guidelines prescribed in EBO 188.

v. Enbridge maintains its Rolling Project Portfolio at a PI level greater than 1.0 as per guidelines prescribed in EBO 188.

Witnesses: F. Ahmad
I. MacPherson

APPrO INTERROGATORY #13

INTERROGATORY

Reference: EB-2012-0451, Ex I.A1.EGD.APPrO 1i) and EB-2012-0451 (Filed: 2012-12-21) Exhibit A Tab 3 Schedule 1 paragraph 9.

In the first reference, EB-2012-0451, Enbridge indicates that the GTA reinforcement will result in reserve capacity. As an example of such reserve capacity Enbridge notes that the reserve capacity at Station B will be 130 TJ/d by 2025. Furthermore Enbridge indicates in the second reference that:

> *In general, the reserve or unutilized capacity in the existing XHP infrastructure is used to accommodate necessary pressure and/or flow reductions required to mitigate downstream vulnerabilities, manage day-to-day maintenance, integrity programs, unplanned events, and balance system flows. Without such capacity, the Company is concerned that significant outages to customers may result from these downstream vulnerabilities.*

Preamble: Some of the reinforcement projects result in Reserve Capacity. Using the above definition, APPrO would like to understand how the costs of this Reserve Capacity are allocated.

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) Please confirm that Reserve Capacity in distribution system is in excess of Advance Capacity. If not explain.

b) Please explain how the costs of providing this Reserve Capacity have been allocated to rate classes.

c) Please provide the amount of reserve capacity that exists or is being proposed in each of the XHP systems referred to in Exhibit B2 Tab 10 Schedule 1 pages 41-49

Witnesses: A. Kacicnik
M. Kirk
E. Naczynski

d) Please provide Enbridge's views on the appropriateness of allocating the cost of this capacity to rate classes that utilize this type of capacity using an allocator that adds the Reserve Capacity to the respective peak day volumes capacity allocator by rate class or alternatively collects the cost of such Reserve Capacity on a per customer charge basis.

e) Re-run Enbridge's Cost Allocation Model filed in this proceeding for the period 2014 to 2018 by allocating the costs of Reserve Capacity to those distribution customers that directly benefit from the use of such Reserve Capacity and provide the results of the model run in the same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule 1. Based on the results above please provide the rates and proposed rate increases to all customers for the years 2014, 2015, 2016, 2017 and 2018

f) With respect to the GTA reinforcement project please confirm that Rate 125 customers receive point to point service between the City Gate Station and its Terminal Location as specified in their contract, and that such customers have no contractual right to access supplies from alternate Gate Stations into the system as is contemplated by the GTA reinforcement project.

<u>RESPONSE</u>

a) The Company does not differentiate between advance and reserve capacity. Reserve capacity is any residual capacity in a system that can be used to manage operational upsets.

b) The Company's cost allocation methodology allocates the test year revenue requirement to the customer classes acting as a guide to rate design. Once a pipeline is put into service, associated costs (i.e., annual revenue requirement) will be recovered in the test year from the customer classes applying the Board approved cost allocation and rate design methodologies. If the assets in question are part of the XHP system, the cost of the XHP system is recovered from the customer classes based on the Delivery Demand TP allocator which is discussed in the response to APPrO Interrogatory #14 at Exhibit I.C30.EGDI.APPRO.14.

c) The amount of reserve capacity that exists or is being proposed in each of reference reinforcements is minor.

   Reinforcements are planned in a manner such that economies of scale in pipeline installation and meeting market growth are optimized. These projects conform to the EBO 188 guidelines for system expansion.

Witnesses: A. Kacicnik
M. Kirk
E. Naczynski

For example, please refer to EB-2011-0323 Exhibit A, Tab 3, Schedule 2, page 3 of 5 (the referenced table is also provided on the next page) for phased Alliston reinforcements. This table shows the load versus capacity for the Alliston reinforcements, which is typical of the reinforcements listed in Exhibit B2, Tab 10, Schedule 1. These reinforcements were phased such that only for short periods of time installed capacity exceeds demand.

d) and e) Please see the response to APPrO #11, part a) iv at Exhibit I.C30.EGDI.APPrO.11 and the response to part c) above.

Also, note that adding reserve capacity of a specific project(s) to the respective customer class peak day allocators would result in more other (i.e. other than the specific project) costs being allocated to the respective customer classes (and the allocators used would no longer reflect design peak day).

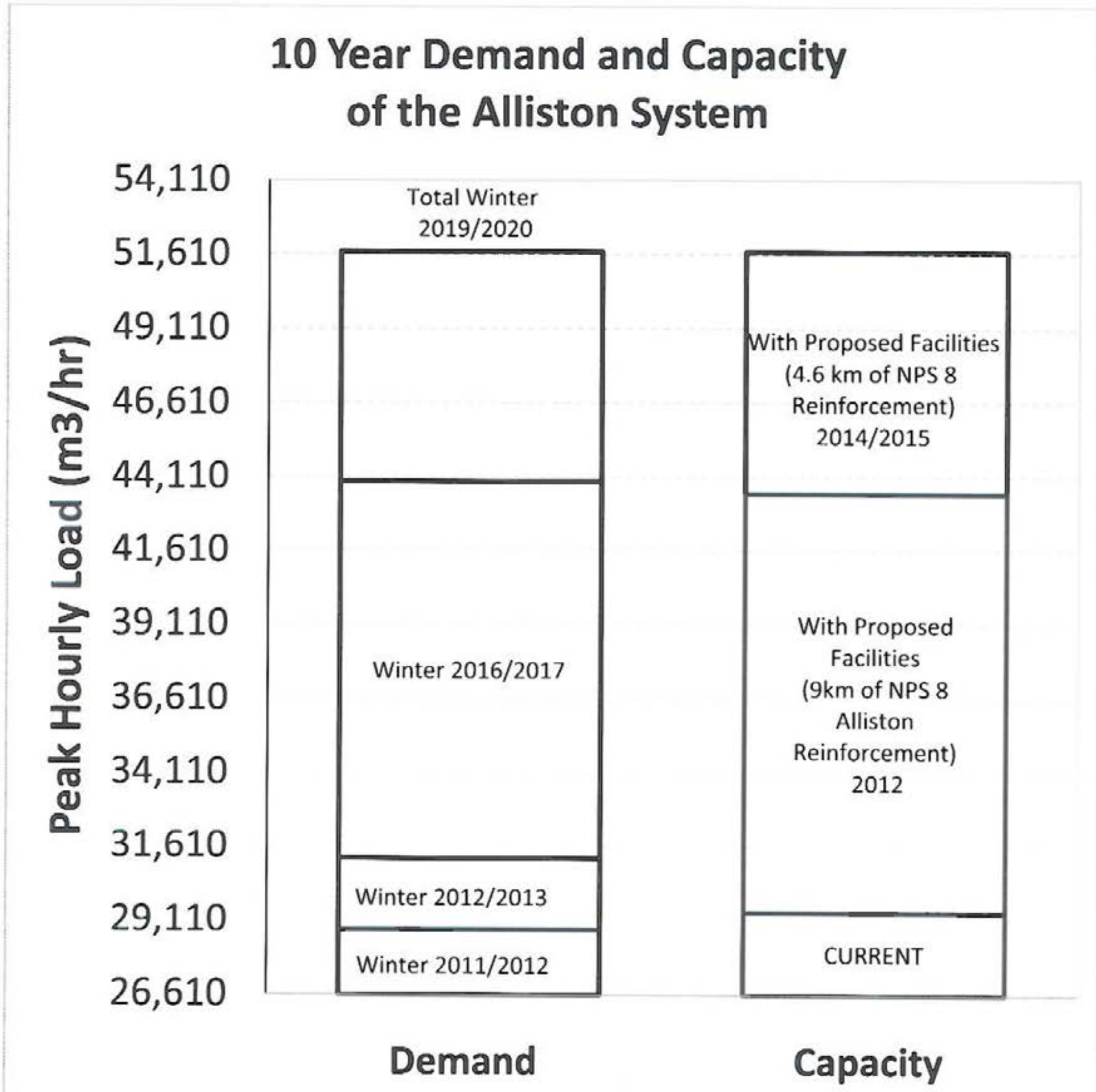
The Company's rates are designed to recover the test year revenue requirement of an integrated system. The use of postage stamp rates in such an integrated system is supported by the costing of each service at the customer class average. This approach to setting rates does not differentiate between specific investments or the mix of investment vintages.

Accordingly, the Company does not have annual revenue requirements associated with specific projects (unless the project has a Y-factor treatment within an incentive regulation plan period) or revenue requirements that would be associated with reserve capacity. This would be a required derivation/determination to collecting the cost of reserve capacity on a per customer charge basis. Please note that the amount of reserve capacity and associated revenue requirements would change annually.

f) Not confirmed. Rate 125 customers have options/choices regarding their upstream arrangements/agreements. The delivery area that the customer would deliver their supplies to would be a function of their upstream pipeline/gas delivery arrangements. As per Rate 125 provisions, the customer may nominate gas to a contractually specified delivery area as specified in the applicable contract with the customer.

Witnesses: A. Kacicnik
M. Kirk
E. Naczynski

FIGURE 1: 10 YEAR DEMAND AND CAPACITY OF THE ALLISTON SYSTEM



Witnesses: A. Kacicnik
M. Kirk
E. Naczynski

APPrO INTERROGATORY #14

INTERROGATORY

Reference: Exhibit G2, Tab 1, Schedule 1

Preamble: APPrO would like to better understand the XHP system capacity allocators used in Enbridge's Cost Allocation Methodology

Issue: 30. Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

Questions:

a) In Exhibit G2, Tab1, Schedule 1, page 27 Appendix B, it shows that the allocation factor used for TP Demand is "Peak throughput on the transmission pressure system".
   i. Please confirm that the allocators used for TP Demand are those shown as "2.1 Delivery Demand TP" in Exhibit G2, Tab 6, Schedule 3, page 1 and that these allocators reflect peak daily throughput.
   ii. Please confirm that distribution mains are designed and modeled from a network analysis perspective, on a peak hour basis. If not please explain in full.
   iii. For each rate class or groups of rate classes, please explain in detail the methodology used to determine the peak daily demand. Please explain how the peak hour load is converted to a peak daily load for calculation of the peak daily load.
   iv. For heat sensitive loads, please confirm that the peak hour and peak daily loads have been adjusted to reflect Enbridge's current approved design day temperature standard for each region.
   v. Please provide the typical hourly load profile graph over a 24 hour period of Enbridge's heat sensitive market by rate class and in aggregate on a design day. On this graph, please illustrate the peak hourly demand, average hourly demand, and the Delivery Demand TP ÷ 24.

b) TP Demand
   i. Please re-run the Cost Allocation Methodology for the period 2014 to 2018 by allocating the TP Demand to customer classes using the peak hour load and not the peak daily throughput and provide the results of the model run in the

Witnesses: A. Kacicnik
M. Kirk

same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule 1.

ii. Based on the results of a) above please provide the rates and proposed rate increases to all customers for the years 2014, 2015, 2016, 2017 and 2018

c) Please re-run the Cost Allocation Methodology for the period 2014 to 2018 incorporating the Cost Allocation Methodology changes outlines in the above interrogatories and provide the results of the model run in the same format as shown for the exhibits from Exhibit G2, Tab 2, Schedule 1 to Exhibit G2, Tab 6, Schedule:

  i. Allocating to rate 125 customers only those XHP system assets that are reasonably capable to supply service to them
  ii. Allocating the costs of Advance Capacity to those distribution customers that directly benefit from the use of such Advance Capacity
  iii. Allocating the costs of Reserve Capacity to those distribution customers that directly benefit from the use of such Reserve Capacity
  iv. Allocating the TP Demand to customer classes using the peak hour load and not the peak daily throughput

d) Based on the results of c) above please provide the rates and proposed rate increases to all customers for the years 2014, 2015, 2016, 2017 and 2018

RESPONSE

a)

  i. Confirmed.

  ii. Confirmed.

  iii. From the top down (i.e., system total) perspective, design peak day demand is forecast utilizing a regression analysis. For each of the three weather zones contained within Enbridge's franchise area a separate regression equation is developed. Within each regression equation actual peak day demand (i.e., as measured at gate station entry points into the system excluding flows/demand of unbundled customers) is expressed as a function of weather variables and the number of customers. The peak day demand forecast by weather zone is then determined by utilizing design weather conditions and projected customer numbers as inputs to these regression equations. The total (i.e., system wide) design peak day demand for bundled customers is determined by summing the design peak day demand forecasts produced by each regression equation.

From the network analysis perspective, it is important to note that the Company does not measure peak hourly or daily consumption for the vast majority of its customers. The peak load is derived from actual customer consumption volumes extracted from Enbridge's billing system. An extract of 24 months of actual customer consumption volumes and corresponding temperature readings are used in a mathematical regression to determine the base load and heat load for various customer sectors. The base load and heat load are aggregated to sector (i.e., residential, apartment, commercial, and industrial) and to each region. The sum of the base load and heat load then results in peak consumption estimates for the forecast period.

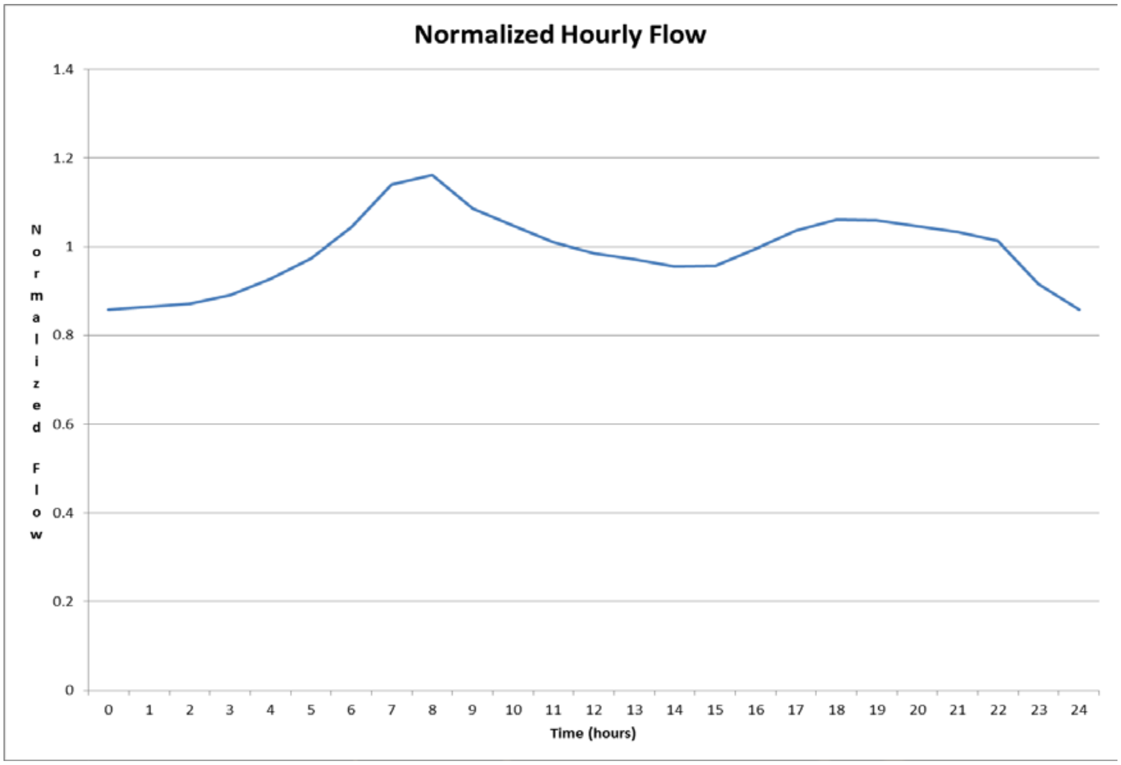
For unbundled customers, the sum of the customers' contract demands or billing contract demands is used as peak day demand.

iv. Confirmed. The forecast peak daily demand is adjusted for bundled customers to meet the design day criteria. This is not the case for unbundled customers, whose contract demand or billing contract demand is not adjusted with respect to the design day criteria.

Note that for bundled customers, the design peak day demand represents peak hourly demand times 20 (rather than 24). This accounts for the varying level of bundled customers' volume/demand within a day, since consumption for these customers varies over a 24 hour period.

v. Below is a graph depicting a typical normalized 24-hour gate station load profile showing the heat sensitivity of the load:

Witnesses: A. Kacicnik
M. Kirk



b), c) and d)

TP Capacity costs are allocated to rate classes based on the contribution of each rate class to the peak demand day. As mentioned in part a) iv), the forecast peak daily demand is adjusted for bundled customers to meet the design day criteria. For unbundled customers, the sum of the customers' contract demands or billing contract demands is used as peak day demand.

The following table shows contract parameters for Rate 125 customers on an aggregated basis.

	CD & Billing CD	CD	Maximum Hourly Demand
Rate 125	9,935,357*	15,626,561	651,107

*See Exhibit G2, Tab 6, Schedule 3, Page 1, Line 4, Column 8

Witnesses: A. Kacicnik
M. Kirk

As proposed in the evidence, Rate 125 customers, based on the sum of contract demand and billing contract demand, represent approximately 8.6% of the Delivery Demand TP for 2014.

	Peak Day Demand	% of Peak Day Demand
Bundled	105,004,800*	91.4%
Rate 125 (CD & Billing CD)	9,935,357	8.6%
Total Peak Day Demand	114,940,157**	100.0%

* See Exhibit G2, Tab 6, Schedule 3, page 1, Line 1.4 for Bundled Peak Delivery, and Exhibit D3, Tab 3, Schedule 3, page 1, Line 1 (3,961,350 GJs or 105,100 103m3)

** See Exhibit G2, Tab 6, Schedule 3, page 1, Line 2.1 (difference of 15.6 is Rate 300)

Should the contract demand be used, then Rate 125 customers would represent approximately 13.0% of the Delivery Demand TP for 2014.

	Peak Day Demand	% of Peak Day Demand
Bundled	105,004,800	87.0%
Rate 125 (CD)	15,626,561	13.0%
Total Peak Hourly Demand	120,631,361	100.0%

Should the peak hour load be used to derive the Delivery Demand TP allocator then Rate 125 customers would represent approximately 11.0% of the Delivery Demand TP for 2014.

	Peak Hourly Demand	% of Peak Hourly Demand
Bundled	5,250,240*	89.0%
Rate 125	651,107	11.0%
Total Peak Hourly Demand	5,901,347	100.0%

* Bundled Design Peak Day of 105,004,800 divided by 20 equals 5,250,240

Witnesses: A. Kacicnik
M. Kirk

Note that if the peak hour load is used to derive the Delivery Demand TP allocator then the billing contract demand cannot be used to derive the Delivery Demand TP allocator for Rate 125 customers since the concept of billing contract demand is a daily value.

Also note that the maximum hourly demand is about 1/15 of Rate 125 contract and billing demand.

The as-proposed-for allocators (using the Board approved methodology) result in the amount allocated to unbundled customers which is less than it would be if Delivery Demand TP were allocated using the peak hour load.

It can be inferred from the information above that the rates and proposed rate increases would be higher for Rate 125 under such an approach versus using the Board approved methodology. Consequently and also given that it would be an onerous exercise to do so, the Company respectfully declines to re-run its cost allocation methodology as suggested by the question.

Witnesses: A. Kacicnik
M. Kirk

CCC INTERROGATORY #29

INTERROGATORY

Issue C30 – 2014 Cost Allocation Study

(Ex. G) Please describe any changes EGD has made to the 2013 Board approved costs allocation study for 2014.

RESPONSE

The Company has not made any changes to the cost allocation study for 2014. The Company has, however, highlighted the treatment of Customer Care/CIS within the study, as its revenue requirement reflects the Customer Care/CIS Settlement Agreement and is separate from the derivation of the Company's other 2014 revenue requirement components (i.e., it is shown as a stand-alone item at Exhibit F3, Tab 1, Schedule 2, page 1). A description of how Customer Care/CIS is treated within the Cost Allocation methodology is outlined at Exhibit G1, Tab 1, Schedule 1.

Witnesses: A. Kacicnik
M. Kirk

CME INTERROGATORY #15

INTERROGATORY

Issue: C30

Reference: Exhibit G1, Tab 1, Schedule 1
Exhibit G2, Tab 1, Schedules 1 to 7 inclusive

Please advise whether any changes have been made to the methods used to allocate costs. If so, then please describe each of the changes and their impacts.

RESPONSE

Please see the response to CCC Interrogatory #29 at Exhibit I.C30.EGDI.CCC.29.

Witnesses: A. Kacicnik
M. Kirk

OAPPA INTERROGATORY #5

INTERROGATORY

Issue 30 - Is Enbridge's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to 2014 Fiscal Year rates, appropriate?

5. *(Reference: Exhibit G2, Tab 2, Schedule 2)* - For each of the contract rate classes where the revenue to cost ratio in line 6 differs from that on line 7, please explain the rationale for the difference.

RESPONSE

Revenue to cost ratios measure the amount of forecast revenue to be recovered from a rate class relative to the amount of costs allocated to the rate class from the Company's Fully Allocated Cost Study ("FACS"). The Company attempts to set revenue to cost ratios as close to 1.0 as possible. FACS results are used as a guide for rate design, but maintaining – or improving – revenue to cost ratios year over year for all rate classes is not always feasible. Other competing rate design objectives such as rate impacts and rate stability may lead revenue to cost ratios to change on an annual basis.

Relative to general service customers, revenue to cost ratios for contract rate classes are more likely to change year over year, as they are more sensitive to changes in forecast volumes, contract demand, load factor, and number of customers.

Further, given that contract rate classes are smaller than general service classes (in terms of revenues and costs), any change in year over year revenues/costs has a more pronounced effect on the revenue to cost ratio (i.e., numerator/denominator are much smaller) as compared to the general service classes.

Witnesses: J. Collier
A. Kacicnik
M. Kirk

CME INTERROGATORY #16

INTERROGATORY

Issue: C31

Reference: Exhibit H1, Tab 1, Schedule 1, pages 3 and 8
Exhibit H3, Tab 1, Schedule 1, Appendix A

Tables 1 and 2 in Exhibit H1, Tab 1, Schedule 1 show 2014 Average Rate Impacts excluding and including SRC. Estimated 2015 and 2016 Rate Impacts are shown in Exhibit H3, Tab 1, Schedule 1. In connection with this evidence and the preliminary Revenue Deficiency amounts for 2017 and 2018 of $166.1M and $215.7M respectively shown in Exhibit F, Tab 1, Schedule 3, Appendix A, please provide in one schedule the Rate Impacts for 2014 to 2018 inclusive in the format of Tables 1 and 2 in Exhibit H1, Tab 1, Schedule 1.

RESPONSE

The chart below reflects the average rate impacts from 2014 to 2018 excluding SRC.

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
	2014	2015	2016	2017	2018
Rate Class	T-Service Rate Impact	T-Service Rate Impact	T-Service Rate Impact	T-Service Rate Impact	T-Service Rate Impact
1	-1.7%	2.1%	4.6%	2.4%	2.5%
6	-1.8%	1.6%	4.5%	2.4%	2.5%
9	-1.3%	0.0%	0.0%	0.0%	0.0%
100*	-11.1%	0.0%	0.0%	0.0%	0.0%
110	-1.2%	1.1%	1.9%	0.9%	0.9%
115	-0.2%	1.2%	1.9%	0.9%	0.9%
135	0.0%	0.9%	1.9%	0.8%	0.9%
145	-0.5%	1.1%	2.1%	0.9%	0.9%
170	-0.4%	0.9%	1.7%	0.7%	0.7%
200	-2.5%	0.9%	1.9%	0.8%	0.8%
	Delivery Rate Impact	Delivery Rate Impact	Delivery Rate Impact	Delivery Rate Impact	Delivery Rate Impact
125	-0.9%	2.1%	10.0%	9.9%	9.9%
300	-0.9%	2.1%	10.0%	9.9%	9.9%

*Rate 100 redesign

Witnesses: J. Collier
A. Kacicnik

Please note that the 2014 rate impact percentages reflect the update to the 2014 gas supply plan.

For average bill impacts including SRC refund, please refer to “Sample Typical Customer Estimated T-service Bill Impacts from 2013 to 2018”, at Exhibit H3, Tab 1, Schedule 2, Appendix C, page 1 and the response to OAPPA Interrogatory #4 at Exhibit I.A.8.EGDI.OAPPA.4.

Witnesses: J. Collier
A. Kacicnik